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Implementing Agreement for a Programme of Research and Development on Wind Energy Conversion Systems

Annex IIIa:
Integration of Wind Power into National Electricity Supply Systems

Operating Agent:
Project Management for Energy Research (PLE)
of the Nuclear Research Establishment Jülich (KFA)
on behalf of the Federal Minister of Research and Technology

Contractor:
University Regensburg, Germany

Participating Countries:
Federal Republic of Germany, Japan, The Netherlands, Sweden and the United States of America

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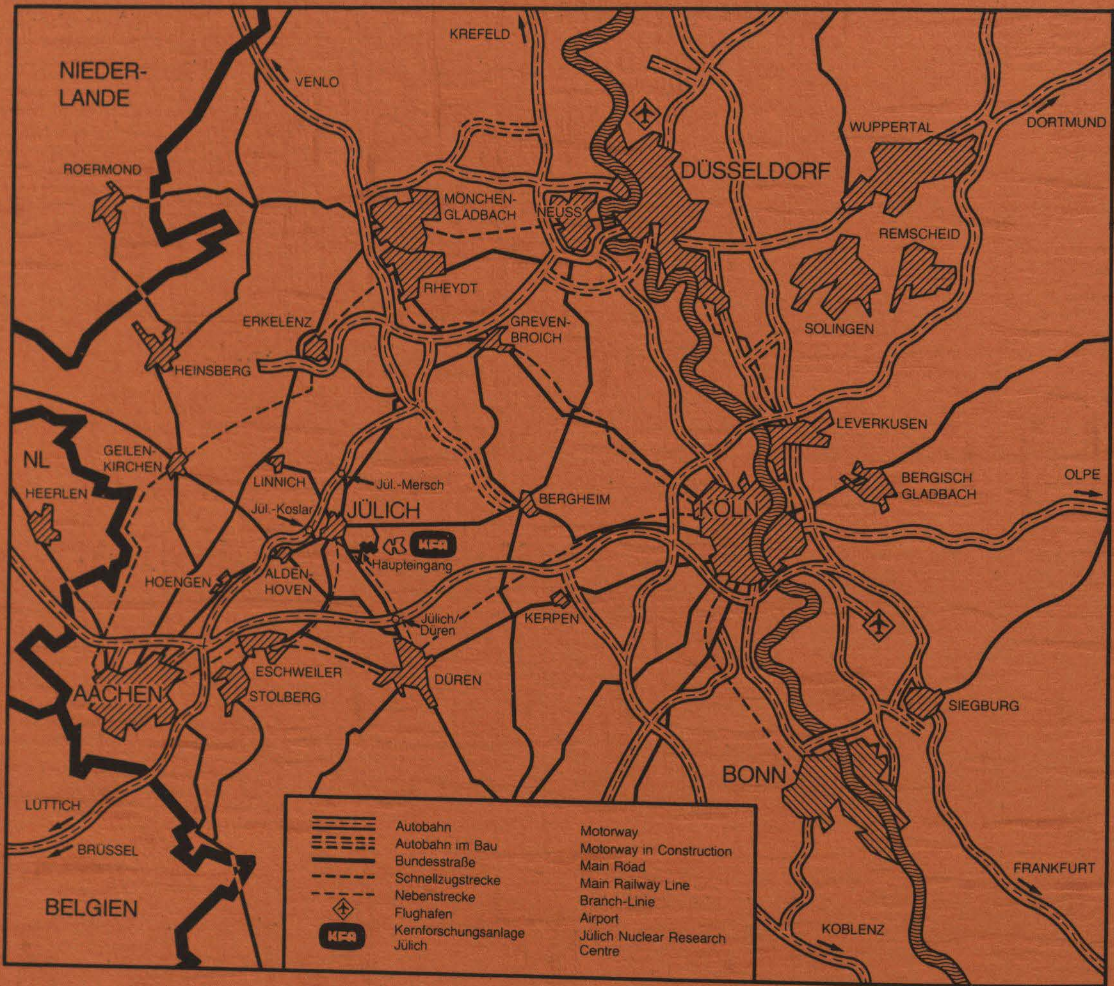

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Authors of the Report: W. Dub. and H. Pape (University Regensburg)
Coordinator Operating Agent: R. Windheim (PLE)

FOREWORD

This report summarizes four case studies concerning the value of large scale wind turbines to electric utilities.

This report as well as the reports on the studies for the Participants Japan, the Netherlands, Sweden and the United States of America are commissioned by the International Energy Agency and carried out by the Wind Energy Group, University of Regensburg.

The Operating Agent is the Minister for Research and Technology of the Federal Republic of Germany, represented by the Kernforschungsanlage Jülich, Projektleitung Energieforschung.

The scientific coordination is held by Prof. Dr. L. Hoffmann, Department of Economics, University of Regensburg, and Prof. Dr. G. Obermair, Department of Physics, University of Regensburg.

The authors like to express appreciation for the cooperation and assistance of the following former and present Members of the IEA R&D WECS Executive Committee:

L.V. Divone (DOE; Chairman), B. Pershagen (Studsvik Energiteknik AB; Secretary), C. Aspliden (DOE), L. Brandels and S. Engström (National Swedish Board for Energy Source Development), T. Makino (MITI), T. Mukai (Japanese Delegation to the OECD), P.F. Sens (ECN Research Center) and R. Windheim (KFA Jülich).

Regensburg, July 1982 W. Dub, H. Pape

Executive Summary

The report describes a methodoly for the analysis of the value of large-scale wind turbines to electric utilities. The methodology is applied to meteorological, wind turbine, utility and socioeconomic data in four case studies. The value analysis was carried out for the year of reference 1985 and included different levels of wind turbine penetration.

Detailed results of the value analysis are given in Chapter 1 (wind data evaluation), Chapter 2 (wind turbine generation), Chapter 4 (megawatt-sized capacity credit) and Chapter 5 (present value per wind turbine system). In Chapter 3, a detailed discussion of the utility planning procedures in current use, and of the unique problems of the integration of wind power into the utility generation system is given. In Chapter 6, observations and conclusions regarding the current and future potential of wind power for utilities are presented.

The investigations are carried out for the countries Japan, the Netherlands, Sweden and the United States of America.

The escalations of fuel prices and the impending scarcity of fossil fuels as well as strong public objection against nuclear power plants and fossil fuel burning facilities have increased interest in the use of wind energy for electricity generation. Especially, research, development and demonstration programs on large scale wind turbines were launched. In order that parks

of wind turbines will be added to the generation mix, cost-effectiveness must be assured at all.

Because, at the time of this writing, large wind turbines are in a state of development and not yet commercially viable, their actual costs are uncertain. Taking into account these unknows, a revenue requirement approach is pursued. The approach determines the breakeven value per wind turbine. The breakeven value is the maximum amount a utility can invest in a wind turbine with no cost or reliability disadvantage.

The breakeven value is realized by displacing high cost energy produced by fossil-fired units by lower cost energy produced by wind turbines (production savings), and by displacing or delaying conventional capacity by the wind turbine capacity (capacity savings). That is, the approach pursued looks at the maximum savings caused by wind turbines in the utility system over some predefined planning horizon.

The value analysis is based upon the assumption that no storage devices are dedicated to wind turbines only.

It must be emphasized that the traditional methodology for utility planning and value analysis cannot be applied to calculate the breakeven value of wind turbines. This is because the stochastic nature of wind calls for new methods in calculation to guarantee system reliability.

The value analysis presented is composed of a series of models which require input data associated with utility system operation, utility financial setup, general economy, wind resource and wind turbines. The value analysis is depicted in Fig. I.

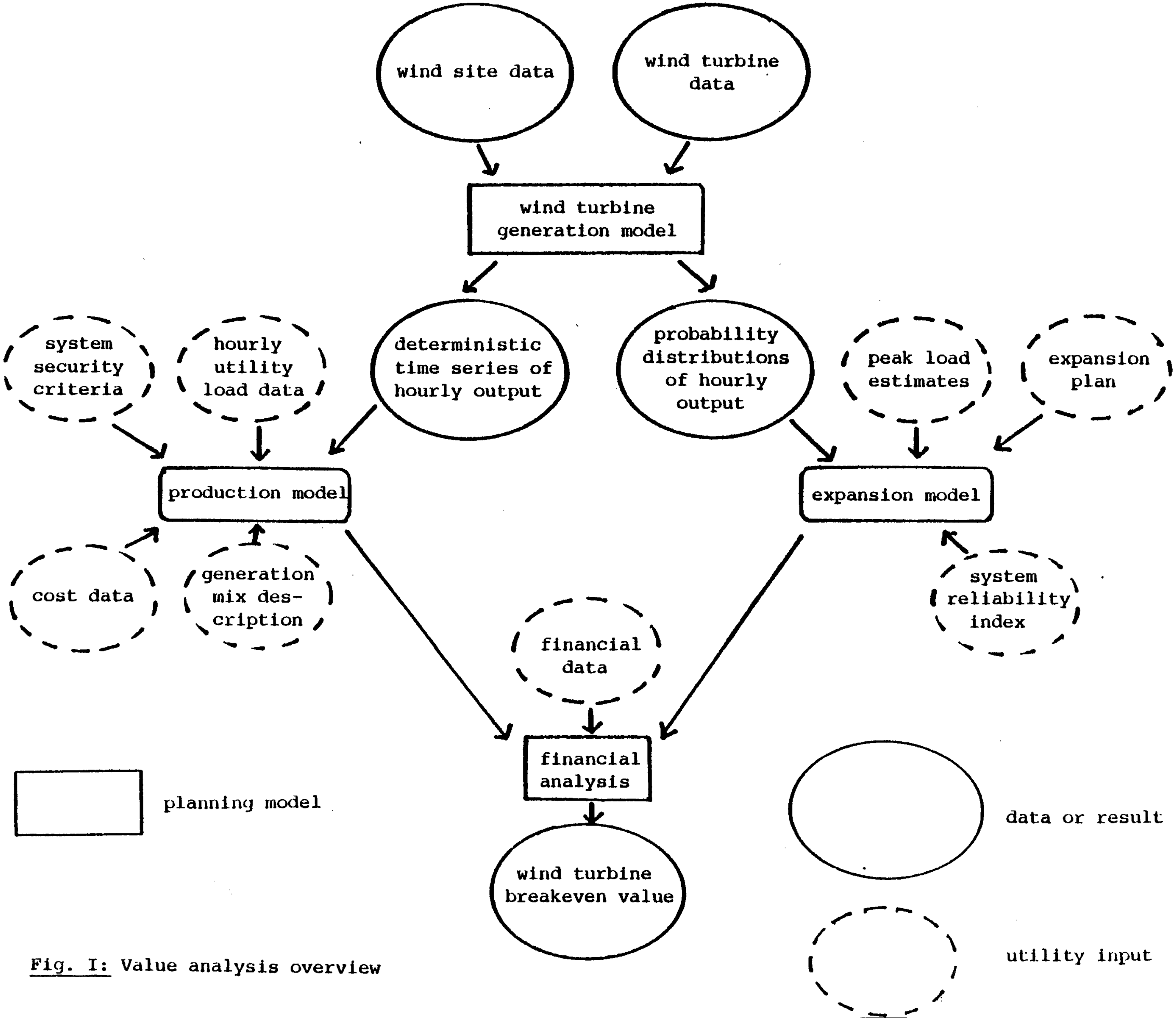


Fig. I: Value analysis overview

In the following a summary of the results and some indicative conclusions of the value analysis for the four Participants are presented.

The main characteristics of the wind speed data and of the sites are listed in Tab. I.

The log law was utilized to convert the velocity data at anemometer height to wind velocity at the hub height of the wind turbine under consideration.

This procedure is based upon several critical assumptions. These assumptions include that:

- The wind speed at hub height is representative for the wind speeds which prevail over the rotor disk.
- The average wind speed is representative for all the wind speeds of the averaging period.
- The extrapolation formula is rather accurate.

The wind turbine output has in principle been calculated by combining hub height wind speeds with the steady-state generation curve as shown in Fig. II.

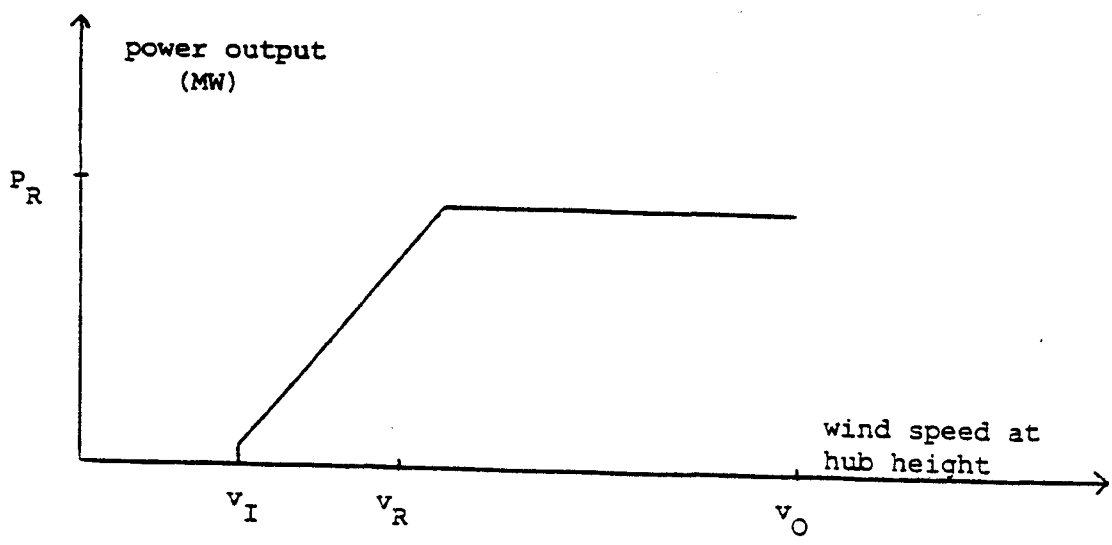


Fig. II: Steady-state performance curve of a wind turbine. P_R: rated power, v_I: cut-in wind speed, v_R: rated wind speed, v_O: cut-out wind speed.

	site	data period	time resolution of wind speeds	measurement height above ground level	missing values
Japan	Esashi	1969 - 1975	three hour average	13 m	0.0 %
	Ibukijama	1969 - 1975		14 m	0.0 %
	Miyakejima	1969 - 1970 / 1972 - 1975		13 m	0.0 %
	Murotomisaki	1969 - 1975		42 m	0.0 %
	Omaezaki	1969 - 1970 / 1972 - 1975		16 m	0.0 %
	Tsukubasan	1969 - 1970 / 1972 - 1975		17 m	0.3 %
the Netherlands	Cabauw	1973	two minute data / half hourly data	10 m / 80 m	4.4 %
	Cadzand	1972 - 1975	mean hourly data	13 m	2.9 %
	Kornwerderzand	1969 - 1975	mean hourly data	10 m	3.4 %
	Terschelling	1969 - 1975	mean hourly data	10 m	5.2 %
	Vlissingen	1969 - 1971 / 1972 - 1975	mean hourly data	to 1971 incl.: 10 m since 1972: 24 m	0.0 %
Sweden	Malmö-Bulltofta / Sturup	1969 - 1975	mean hourly data (integer values)	10 m	0.0 %
	Torslanda	1969 - 1975		10 m	0.0 %
	Visby	1969 - 1975		10 m	0.2 %
USA	San Gorgonio, CA	1979	two minute data	45,7 m	-
	Ludington, MI	11/78 - 10/79	two minute data	45,7 m	-

Tab. I: Sites and wind data characteristics

Four wind turbines were modeled for the report. The parameters utilized in the generation calculations are listed in Tab. II.

wind turbine system	GROWIAN	Aeolus	MOD-2	0.8-MW
manufacturer	MAN-Neue Technologie	Karlstads Mekaniska Werkstad	Boeing	similar to NIBE-A wind turbine
rated power (MW)	3.0	2.0	2.5	0.8
cut-in (m/s)	6.5	6.3	6.3	6.0
rated wind speed (m/s)	12.7	13.1	12.3	12.6
cut-out (m/s)	24.0	21.0	21.0	24.0
hub height (m)	100	80	61	50

Tab. II: Performance parameters of wind turbines

The bandwidth of the annual wind turbine generation is listed in Tab. III. Missing wind speeds had been rehabilitated for power output calculations.

As for Japan, the Netherlands, and Sweden 10 % were subtracted from the values of Tab. III, to account for forced outages of the wind turbines. The output of the two sites in the United States was reduced by 8 %.

Tab. IV gives the percentage of annual hours, the wind speed was either above cut-out or below cut-in wind speed. That considerably improvements can be expected through a site diversity can be seen from Tab. V.

the Netherlands (1969 - 1975)	GROWIAN	0.8-MW
Cadzand (1972 - 1975)	9.1 - 12.6	2.2 - 3.0
Kornwerderzand	9.4 - 11.3	2.3 - 2.7
Terschelling	10.6 - 12.8	2.6 - 3.2
Vlissingen	5.9 - 8.8	1.3 - 2.1
Cabauw (1973)	4.8	1.0
Japan (1969 - 1975)	**GROWIAN**	**0.8-MW**
Ibukiyama	13.4 - 15.5	3.3 - 4.1
Omaezaki	10.3 - 12.0	2.1 - 2.7
Tsukubasan	9.5 - 11.4	2.0 - 2.5
Esashi	5.7 - 9.4	1.4 - 2.3
Miyakejima	8.0 - 11.0	1.8 - 2.6
Murotomisaki	11.0 - 12.5	2.2 - 2.7
Sweden (1969 - 1975)	**GROWIAN**	**Aeolus**
Malmö	8.5 - 10.1	5.2 - 6.0
Torslanda	9.0 - 11.4	5.4 - 6.8
Visby	8.5 - 10.3	5.0 - 6.1
USA	**MOD-2**	
San Gorgonio (1979)	8.1	
Ludington (11/78 - 10/79)	7.8	

Tab.III: Bandwidth of annual WECS power output (GWh)

the Netherlands (1969 - 1975)	GROWIAN	0.8 MW
Cadzand (1972 - 1975)	26 % - 41 %	25 % - 41 %
Kornwerderzand	30 % - 37 %	30 % - 37 %
Terschelling	26 % - 35 %	25 % - 34 %
Vlissingen	41 % - 56 %	42 % - 57 %
Cabauw (1973)	62 %	64 %
Japan (1969 - 1975)	**GROWIAN**	**0.8 MW**
Ibukiyama	21 % - 31 %	24 % - 30 %
Omaezaki	33 % - 40 %	39 % - 44 %
Tsukubasan	39 % - 46 %	40 % - 47 %
Esashi	51 % - 65 %	51 % - 65 %
Miyakejima	39 % - 48 %	34 % - 49 %
Murotomisaki	32 % - 36 %	34 % - 40 %
Sweden (1969 - 1975)	**GROWIAN**	**Aeolus**
Malmö	37 % - 46 %	37 % - 46 %
Torslanda	33 % - 43 %	30 % - 41 %
Visby	37 % - 44 %	31 % - 37 %
USA	**MOD-2**	
San Gorgonio (1979)	49 %	
Ludington (11/78 - 10/79)	40 %	

Tab.IV : Percentage of annual hours with no WECS power output - single sites

the Netherlands	GROWIAN	0.8 MW
Cadzand + Kornwerderzand + Terschelling (1972 - 1975)	12 % - 19 %	12 % - 19 %
Japan	GROWIAN	0.8 MW
Miyakejima + Omaezaki + Tsukubasan (1969 - 1975)	8 % - 15 %	9 % - 17 %
Sweden	GROWIAN	Aeoulus
Malmö + Torslanda + Visby (1969 - 1975)	12 % - 19 %	10 % - 16 %

Tab. V : Percentaje of annual hours with no WECS power output - diversity of sites

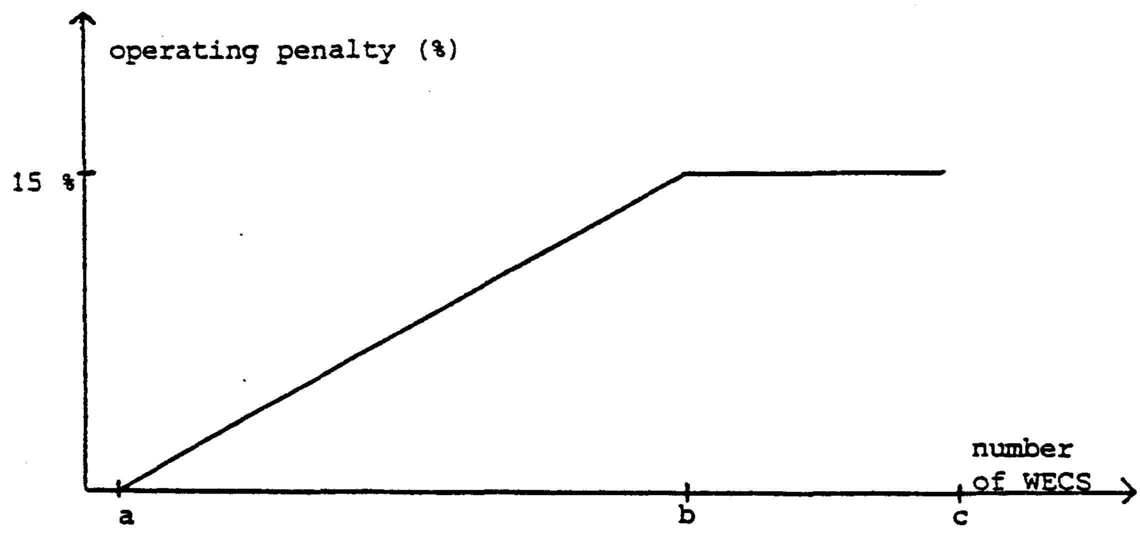
If wind turbines are to be a significant part of an electric utility system, two major questions need to be answered:

- Do parks of wind turbines necessitate the alteration of the present operation strategies?
- Do wind turbines have a capacity credit?

Wind turbines are said to have a capacity credit if they can displace the installation of conventional units (thermal units (including nuclear units) and hydro units). The displacement must be subject to the condition that the system reliability is maintained. This means that a generation mix composed of wind turbines and conventional units must guarantee a power supply with the same degree of reliability as would do a power plant mix merely composed of conventional units.

Up to now the utilities do not have highly stochastic energy sources like wind. Hence, the common utility reliability calculations cannot be applied to wind turbines without additional assumptions. Above all, assumptions regarding the time dependence of wind power have to be made. Whether the utilities will accept the assumptions and hence the capacity credit, will strongly depend on the performance of wind turbines.

Because the wind is available intermittently, the utility has minimum control over the level of wind generation at any time. To secure operation, the regulating capacity and the load following capability of a wind-assisted system has to be enlarged to protect against any wind power shortfalls and wind power variations during operation. The changes in unit commitment and dispatch result in an increased spinning reserve, an increased unloadable generation, an enlarged wear of the conventional units and additional labor. These costs are imposed as operating penalty on the wind turbines. The operating penalty consists in subtracting up to 15 % from the wind turbine output which already is adjusted for forced outages. The operating penalty is sketched below.



a: number of WECS such that the sum of the WECS nameplate capacities amounts to 1 % of the expected minimum load in 1985

b: number of WECS such that the penetration rate of WECS (sum of WECS nameplate capacities / total installed thermal capacity in 1985) amounts to about 10 %

c: maximum number of WECS

The breakeven value of the wind turbine is composed of the present value of the production savings and of the present value of the capital savings. The production savings comprise the fuel savings and corresponding variable operation and maintenance savings. The capital savings are given by the capital costs of the displaced conventional unit(s) and corresponding fixed operation and maintenance savings.

The fuel cost data which entered the calculations of the production savings are given in Tab. VI.

fuel	Japan	the Netherlands	Sweden	USA
oil	0.096	0.079	0.071	0.1
gas	0.084	0.079	-	-
coal	-	0.038	0.034	0.02

Tab. VI: Estimated BOY 1985 fuel cost in $/kWh
1 US $ = 226.77 Yen = 2.5 hfl = 5.56 skr

Economic input parameter assumptions, generation characteristics, and cost estimates of the value determination are listed in Tab. VII. The predefined planning horizons cover the time spans 1985 - 2005 (2015).

	Japan	the Netherlands	Sweden	USA San Gorgonio	USA Ludington
ratio of displaced fuels in the utility system	oil : gas = 5 : 5	oil/gas : coal = 7 : 3	oil : coal = 8 : 2	oil : coal = 9 : 1	oil : coal = 4 : 6
fuel cost in 1985 $/kWh	0.09	0.0667	0.0636	0.092	0.052
variable O & M cost in 1985 $/kWh	0.0044	0.004	0.0036	0.0035	0.0035
fixed O & M cost in 1985 $/kW	66	48	54	3	3
annual escalation rate of O & M cost (incl. inflation)	5 %	7 %	8 %	8 %	8 %
capital cost in 1985 $/kW	792	800	900	650	650
lowest/highest annual wind turbine output (GWh per year)	GROWIAN: 9/11 0.8 MW 1.5/2.5	GROWIAN: 9/12 0.8 MW 2/3	GROWIAN: 9/11 Aeolus: 5/7	MOD-2: 8.09	MOD-2: 7.82
lowest/highest annual escalation rate of fuel cost (incl. inflation)	5%/8%	8%/10%	3%/12%	9%/10%	9%/10%
wind turbine operating lifetime in years	20 / 30	20 / 30	20 / 30	20 / 30	20 / 30
constant discount rate (incl. inflation)	9 %	11 %	12 %	12 %	12 %
constant inflation rate	5 %	7 %	8 %	8 %	8 %

Tab. VII: Parameter input to determine the breakeven value per wind turbine

In the following tables of the breakeven values, the lower (upper) range of the production savings follows from a 'worst' ('best') case. The 'best' case is the one with the highest annual wind turbine output and the highest escalation rate of fuel prices. The 'worst' case is the one with the lowest annual wind turbine output and the lowest escalation rate of fuel prices.

Penetration is defined in Tab. VIII through Tab. XI as the rated capacity of the wind turbines, related as a percentage to the peak demand of each system. The systems are

- Tokyo Electric Power Company (Japan)
- Dutch system in total
- Swedish system in total
- Southern California Edison (San Gorgonio); Consumers Power Company / Detroit Edison (Ludington) (USA)

For a complete derivation of the results, and an extensive discussion of the results, the reader is referred to the reports for the Participants in the Task.

	Japan		the Netherlands		Sweden		
number of wind turbines	100	1000	100	1000	100	1000	
penetration in 1985	0.82	8.2	2.6	26	1.47	14.7	
GROWIAN	3657-5658	3230-4997	2919-3410	2522-2946	2583-4299	2232-3714	production savings
lifetime: 20 years	355	253	472	216	646	395	capital savings
	4012-6013	3483-5250	3391-3882	2738-3162	3229-4945	2627-4109	breakeven value
GROWIAN	4683-8087	4137-7144	3871-4873	3344-4210	3320-6413	2868-5540	production savings
lifetime: 30 years	409	295	535	244	731	488	capital savings
	5092-8496	4432-7439	4406-5408	3588-4454	4051-7144	3316-5988	breakeven value

Tab. VIII: Breakeven value of GROWIAN in 1985 $ per kW

	Japan		the Netherlands		
number of wind turbines	100	1000	100	1000	
penetration in 1985	0.22	2.2	3.5	7	
0.8 MW wind turbine	2285-4822	2285-4822	2472-2888	2322-2713	production savings
lifetime: 20 years	263	249	494	422	capital savings
	2548-5085	2534-5071	2966-3382	2744-3135	breakeven value
0.8 MW wind turbine	2927-6892	2927-6892	3279-4127	3080-3877	production savings
lifetime: 30 years	303	286	559	477	capital savings
	3230-7195	3213-7178	3838-4686	3557-4354	breakeven value

Tab. IX: Breakeven value of 0.8 MW wind turbine in 1985 $ per kW

	Sweden		
number of wind turbines	100	1000	
penetration in 1985	0.98	9.8	
Aeolus lifetime: 20 years	2153-4104	1860-3545	production savings
	659	417	capital savings
	2812-4763	2337-4022	breakeven value
Aeolus lifetime: 30 years	2766-6121	2390-5288	production savings
	746	540	capital savings
	3512-6867	2930-5828	breakeven value

Tab. X: Breakeven value of Aeolus in 1985 $ per kW

	U S A				
	San Gorgonio		Ludington		
number of wind turbines	100	1000	100	1000	
penetration in 1985	1.7	17	1.76	17.6	
MOD-2 lifetime: 20 years	2906-3211	2575-2789	1631-1766	1410-1527	production savings
	124	22	82	46	capital savings
	3030-3335	2597-2811	1713-1848	1456-1573	breakeven value
MOD-2 lifetime: 30 years	3859-4337	3351-3766	2123-2385	1837-2060	production savings
	125	22	83	47	capital savings
	3984-4462	3373-3788	2206-2468	1884-2107	breakeven value

Tab. XI: Breakeven value of MOD-2 in 1985 $ per kW

The results show that the breakeven value is predominantly (about 88 %) determined by the production savings.

For all the utility/site combinations the production savings decrease with increasing wind penetration. The decrease is due to the need for additional regulating capacity and a more flexible commitment including a shift to more energy-consuming conventional units to compensate for the wind power variations. The calculations indicate that the fuel savings are by far the biggest element of the production savings. The variable O & M savings were always less than 6 % of the production savings. The value of the production savings is most sensitive to the lifetime of the wind turbines. Given a lifetime, the production savings are highly sensitive to the conventional fuel costs and the escalation rate of the fuel costs.

It is seen that the capital savings decrease if the number of wind turbines increases. This can be explained as follows: If the number of wind turbines is small, the variance of the random variable "available wind turbine capacity" is very small compared with the variance of the conventional system. The capacity credit is then approximately given by the expected available wind turbine capacity. If the number of wind turbines increases, the variance of the random variable "available wind turbine capacity" becomes a larger fraction of the total system variance (conventional units and wind turbines). Since the expected available wind turbine capacity increases less than the variance of the "available wind turbine capacity", the capacity credit per wind turbine decreases.

The calculated breakeven value is the maximum amount a utility can invest in the wind turbine system with no cost or reliability disadvantage subject to the specifications of the cases given in Tab. VII.

The breakeven value has to comprise all the costs incurred over the lifetime of the turbine. That is, manufacturers cost and owners cost are included. Cost items are, for example, fabrication, installation, checkout, interfacing, O & M, fees, insurance, land lease.

To date, even a small number of wind turbines on a commercial basis does not exist. The current lack of fully demonstrated wind turbine performance and O & M costs makes a costing risky. Furthermore, costs will depend on a solid market development. However, first cost data are quoted in the literature. The following indications are based on the assumption that the ambitious cost goals can be achieved by the wind turbine manufacturers:

The utilities present value lifetime breakeven values per wind turbine are over the projected wind turbine cost for all the four cases. As in general, oil generation is a tremendous cost burden relative to other fuels, the wind turbines are the more attractive, the more the utility depends on oil generation. If a utility such as CPC/DE depends mainly on coal, the cost target is, however, met by a narrow margin only. All the utilities assessed should further consider wind turbines in their generation plans. More detailed site-dependent assessments are now warranted. In general, our results indicate that even at conservative assumptions wind turbines are likely to become cost-effective for utilities with good wind regimes and a high electricity generation.

Notwithstanding the well-known problems to quantify social costs, the competitiveness of wind turbines tends to grow when an evaluation of social costs is allowed for, since these will certainly be lower for wind energy than for all competing conventional energy sources.

CONTENTS

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INTRODUCTION

The increasing costs and impending scarcity of fossil fuels as well as strong public objection against nuclear power plants and fossil fuel burning facilities have increased interest in the use of wind energy for electricity generation. At the time of this writing field operational testing of numerous large WECS (wind energy conversion systems) is under way. Valuable technical data are gathered through the testing. The technical mastery of large WECS is, of course, a necessary condition for the integration of WECS into the electricity generation mix. The sufficient condition is "cost-effectiveness", however.

The usual approach to cost-effectiveness would be the traditional economic cost-benefit analysis including quantifiable costs and benefits as well as non quantifiable costs (key word: visual pollution) and benefits (key word: no air pollution). Apart from the difficulty to measure non quantifiable costs and benefits which is an inherent but unsolved problem of all economic analyses, the traditional approach cannot be used at present due to the lack of rather accurate WECS cost data. Large WECS are not yet commercially available and the less are reliable WECS cost data. This is the reason that cost-effectiveness with regard to quantifiable costs has been measured via breakeven costs in this study. Non quantifiable costs and benefits are discussed but no attempt has been made to reduce them to a single numerical value.

The breakeven value gives the amount that can be spent on WECS with no cost or reliability disadvantage compared with conventional units. The breakeven value is mainly composed of two components: fuel savings and capacity savings.

Fuel savings result from operating thermal power plants at a lower power level or even shutting them down if wind power is available. High priced fossil fuels can then be saved. Capacity savings result from the displacement of conventional capacity. It must be emphasized that the capacity savings are highly controversial and that utilities are hesitant to take capacity savings. A capacity credit concept which tries to account for the unique characteristics of wind power is presented in Chapter 4.

The unique characeristics of wind power which affect both fuel savings and capacity savings can be summarized by saying that utilities have no control over the power source. Wind power cannot be scheduled for electricity generation in the same way as can conventional units because it is so far unpredictable how many megawatt hours of wind power can be generated in a future time period. Furthermore, if wind power is available, the WECS power output is fluctuating unless the wind speed is above rated wind speed.

It should be obvious that the fluctuations may call for special measures to maintain system reliability if <u>many</u> wind turbines are integrated into the electricity generation mix. The definitive measures will depend on a multitude of data. To name only the most relevant: number and type of WECS; siting of WECS; load share of WECS; accuracy of WECS power output forecast; start-up time, shut-down time and load following capability of conventional units; system operating constraints (the spinning reserve concept). These items will be discussed in greater detail in Chapter 3.

According to the principles of economic analysis, all costs must be attributed to WECS which would not occur without WECS. Since the measures which compensate for the fluctuating WECS power output incur costs which would not arise otherwise, these costs have to be subtracted from the benefits of wind power. This has been done by reducing the fuel savings by a so-called operating penalty. The penalty is deduced in Chapter 5.

It must be emphasized that the estimated breakeven values are meant to be instructive rather than definitive. More detailed utility specific data as well as better wind speed data are required for a more definitive assessment of WECS. For example, we sometimes had to use wind speed data from sites, no large wind turbine will presumably be erected at any time. It must be doubted that similar sites have the same wind regimes. The conclusions which can and cannot be drawn from the wind speed data which had been made available, are mentioned in Chapter 1 and Chapter 2.

One problem of the assessment presented in this study will, however, not vanish if both detailed utility specific data and accurate wind data are available: the uncertainty with regard to future fuel costs. At present, the value of WECS mainly results from the capability of WECS to save fossil fuels. It is therefore not surprising that the breakeven value is highly sensitive to assumptions in fuel costs. The problem that nobody can predict future fuel costs has been taken into account by calculating the breakeven value for different fuel costs and fuel cost escalation rates.

Despite of some limitations due to the data base and despite of the uncertainty to predict future fossil fuel costs, our results indicate that large WECS are likely to be cost-effective even at conservative assumptions.

Detailed results of the analysis will be outlined in the sequel. The substance of the results is always discussed because we believe that the knowledge of the critical points is just as important as the results themselves.

Finally, some limitations shall be listed:

- The study is restricted to assess the value of large scale horizontal axis wind turbines to future wind-assisted utility systems.
- Despite of the intermittent nature of wind, no dedicated storage to wind turbines is considered.
- The electric utility system, which is assessed, is considered being part of an intermittent system.

1. Wind Data

Wind speed and direction data had been provided by

Japan: Mitsubishi Research Institute
the Netherlands: Koninklijk Nederlands Meteorologisch Instituut (KNMI)
Sweden: Swedish Meteorological and Hydrological Institute (SMHI)
the USA: Battelle Pacific Northwest Laboratories.

The main characteristics of the data are listed in Tab. 1.1.

<u>Comment</u>
Two minute data are instantaneous data, recorded at two minute intervals. Mean hourly data (half hourly data) are calculated by averaging over those wind speed and direction data which occur during the last ten minutes of each hour (half hour). Similarly, the averaging period of three hour averages is given by the last ten minutes of the three hour period. It is therefore not self-evident that both the wind speed and direction data are representative for the period (hour, half hour, two minutes) they are assigned to.

Extrapolation of the wind speed data to the hub height of the wind turbines under consideration has been done by the following formula:

$$v(h) = \frac{\ln h - \ln z_o}{\ln h_a - \ln z_o} \cdot v(h_a) \qquad (1.1)$$

where
h: hub height
h_a: measurement height above ground level

	site	data period	time resolution of wind speeds	measurement height above ground level	missing values
Japan	Esashi	1969 - 1975	three hour average	13 m	0.0 %
	Ibukijama	1969 - 1975		14 m	0.0 %
	Miyakejima	1969 - 1970 / 1972 - 1975		13 m	0.0 %
	Murotomisaki	1969 - 1975		42 m	0.0 %
	Omaezaki	1969 - 1970 / 1972 - 1975		16 m	0.0 %
	Tsukubasan	1969 - 1970 / 1972 - 1975		17 m	0.3 %
the Netherlands	Cabauw	1973	two minute data / half hourly data	10 m / 80 m	4.4 %
	Cadzand	1972 - 1975	mean hourly data	13 m	2.9 %
	Kornwerderzand	1969 - 1975	mean hourly data	10 m	3.4 %
	Terschelling	1969 - 1975	mean hourly data	10 m	5.2 %
	Vlissingen	1969 - 1971 / 1972 - 1975	mean hourly data	to 1971 incl.: 10 m since 1972: 24 m	0.0 %
Sweden	Malmö-Bulltofta / Sturup	1969 - 1975	mean hourly data (integer values)	10 m	0.0 %
	Torslanda	1969 - 1975		10 m	0.0 %
	Visby	1969 - 1975		10 m	0.2 %
USA	San Gorgonio, CA	1979	two minute data	45,7 m	-
	Ludington, MI	11/78 - 10/79	two minute data	45,7 m	-

Tab. 1.1: Sites and wind data characteristics

z_o: terrain roughness length
$v(h)$: wind speed at hub height
$v(h_a)$: wind speed at measurement height

z_o- values were either provided by the data sources (KNMI, SMHI) or estimated from [4] according to the description of the surroundings of the measurement station.

Formula (1.1) is based on the law of the logarithmic wind profile; see e.g. [7]. The log law has a better claim to accuracy than the often used power law, [5]. That (1.1) may, however, fail to give good estimates of wind speeds at higher levels is indicated by Fig. 1.1 [5, p. 1-12].

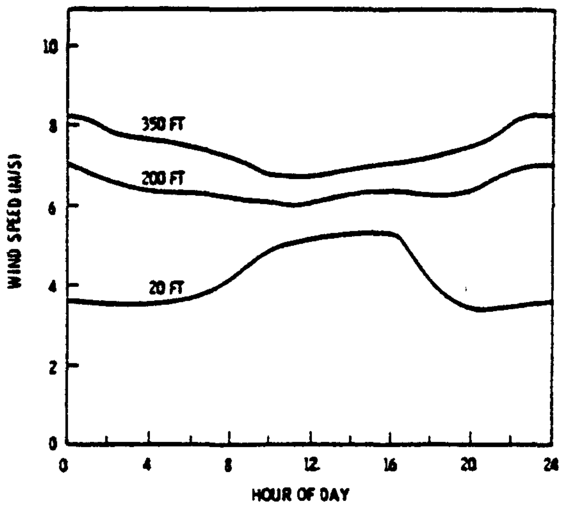

Fig.1.1: Annual average diurnal variation at three elevations. Results are based on a single year of measurement at a site near Oklahoma City, Oklahoma. Elevations correspond to a typical surface measurement height; hub height for a large, horizontal axis wind turbine; and the top of the rotor disk of such a turbine.

Fig. 1.1 is dramatically different than what would have been expected from the extrapolation formula (1.1) with h_a = 20 FT and h = 200 FT or h = 350 FT. If the difference between wind speeds at measurement height is positive (negative), the difference between wind speeds at higher levels is also positive (negative) according to (1.1). Just the opposite is shown in Fig. 1.1. This demonstrates the importance of direct measurements at levels comparable to the height of the wind turbine for a definitive assessment of wind power. For an extensive discussion of the time-dependent nature of the diurnal wind profiles the reader is referred to [2].

The bandwidth of mean annual wind speeds at different heights is listed in Tab. 1.2. The heights correspond to hub heights of wind turbines which are examined in the study.

Ranking the months by the height of the mean monthly wind speed, the tendency shown in Tab. 1.3 hold.

the Netherlands (1969 - 1975)	50 m	100 m
Cadzand	7.6 - 9.0	8.2 - 9.7
Kornwerderzand	7.8 - 8.5	8.4 - 9.1
Terschelling	8.4 - 9.3	8.9 - 9.9
Vlissingen	6.1 - 7.3	6.9 - 7.6
Cabauw	5.5	6.1
Sweden (1969 - 1975)	**80 m**	**100 m**
Malmö	7.2 - 8.2	7.4 - 8.4
Torslanda	7.5 - 9.0	7.7 - 9.3
Visby	7.5 - 8.4	7.7 - 8.6
Japan (1969 - 1975)	**50 m**	**100 m**
Ibukiyama	9.9 - 12.2	10.8 - 13.2
Omaesaki	7.4 - 8.1	9.7 - 10.3
Tsukubasan	7.2 - 8.1	8.3 - 9.4
Esashi	5.3 - 7.1	5.6 - 7.6
Miyakejima	6.9 - 8.5	7.6 - 9.3
Murotomisaki	7.7 - 8.6	9.3 - 10.3
USA	**61 m**	
San Gorgonio (1979)	7.6	
Ludington (11/78 - 10/79)	7.9	

Tab. 1.2: bandwidth of mean annual wind speeds (m/s) in different heights.

	the Netherlands	Sweden	Japan
high winds	Nov.	Nov.	Feb./Jan.
↑	Jan./Dec.	Jan./Dec.	Dec./Mar./Nov.
	Mar./Apr./Oct.	Sep./Oct./Apr.	Apr.
	Feb./May/Sep.	Mar./Feb./May	Oct.
	June/July	June/Aug.	May/Sep.
low winds	Aug.	July	July/Aug./June

Tab. 1.3: Rank order of months by the height of the mean monthly wind speed

It must be emphasized that this is only a weak or long run tendency. Particular years showed different rank orders. At all Swedish measurement stations, for example, the mean wind speed of July 1974 was above the mean wind speed of November 1974.

The corresponding rank order for San Gorgonio and Ludington is given in Tab. 1.4. Since the available data were only for a single year there is some question as to how typical that year might be in that sense, that the long-run tendency is reflected correctly.

	San Gorgonio	Ludington
high winds	Apr.	Nov./Dec.
↑	May/Aug./June	Oct./Jan.
	July/Oct.	Mar.
	Mar./Feb.	Feb./Apr.
	Sep./Nov.	June/May
low winds	Dec./Jan.	Aug./July

Tab. 1.4: Rank order of months by the height of the mean monthly wind speed.

Cost minimum integration of wind turbines into the generation system, as discussed in Chapter 3, requires accurate wind turbine output forecasts for forecasting periods from 10 minutes to about 6 hours. Such forecasts will have to be based on wind speed forecasts. The methods used today by meteorologists fail to give accurate wind speed forecasts [1]. The meteorological forecasts exploit the relationship between wind speed and independent wind related predictors such as pressure, temperature, etc. In order to get a lead on whether forecasts based on a time series analysis of wind speeds can be expected to be quite accurate, a time series analysis was performed within the scope of this study. Periods of 3 hours and 6 hours were analyzed. Data input were two minute wind speeds which had been measured at 80 m height at Cabauw (the Netherlands) in 1973. First, the hypothesis was tested: The two minute wind speed data form a weakly stationary stochastic process in periods of 3 hours (6 hours). That being the case, quite accurate forecasts should be possible. However, the hypothesis had to be rejected (significance level: 0.05) for 1270 out of 1748 3 hour intervals (72.65 %) and for 676 out of 874 6 hour intervals (85.93 %). As for the statistical details, the reader is referred to [3] or [6]. Fig. 1.2 shows two minute wind speed data which could be considered to be a realization of a weakly stationary stochastic process. This does not apply for the time series shown in Fig. 1.3.

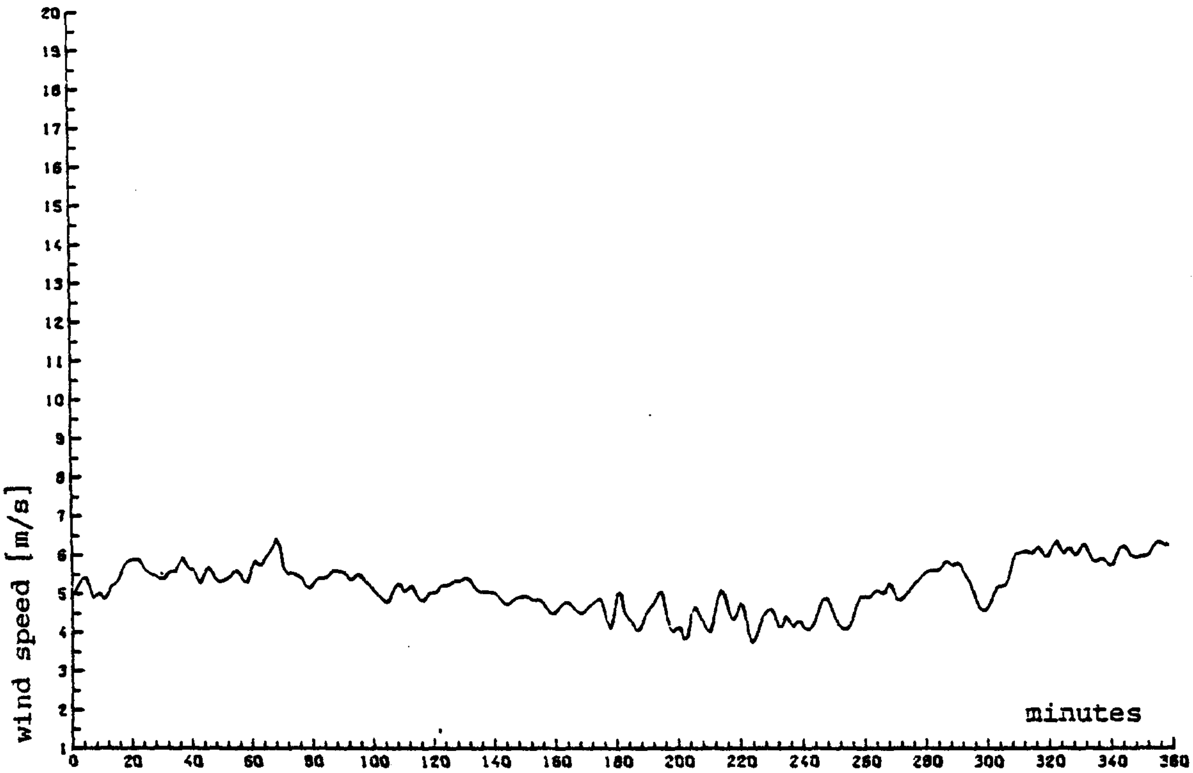

Fig. 1.2: Time series of two minute wind speed data - weakly stationary stochastic process

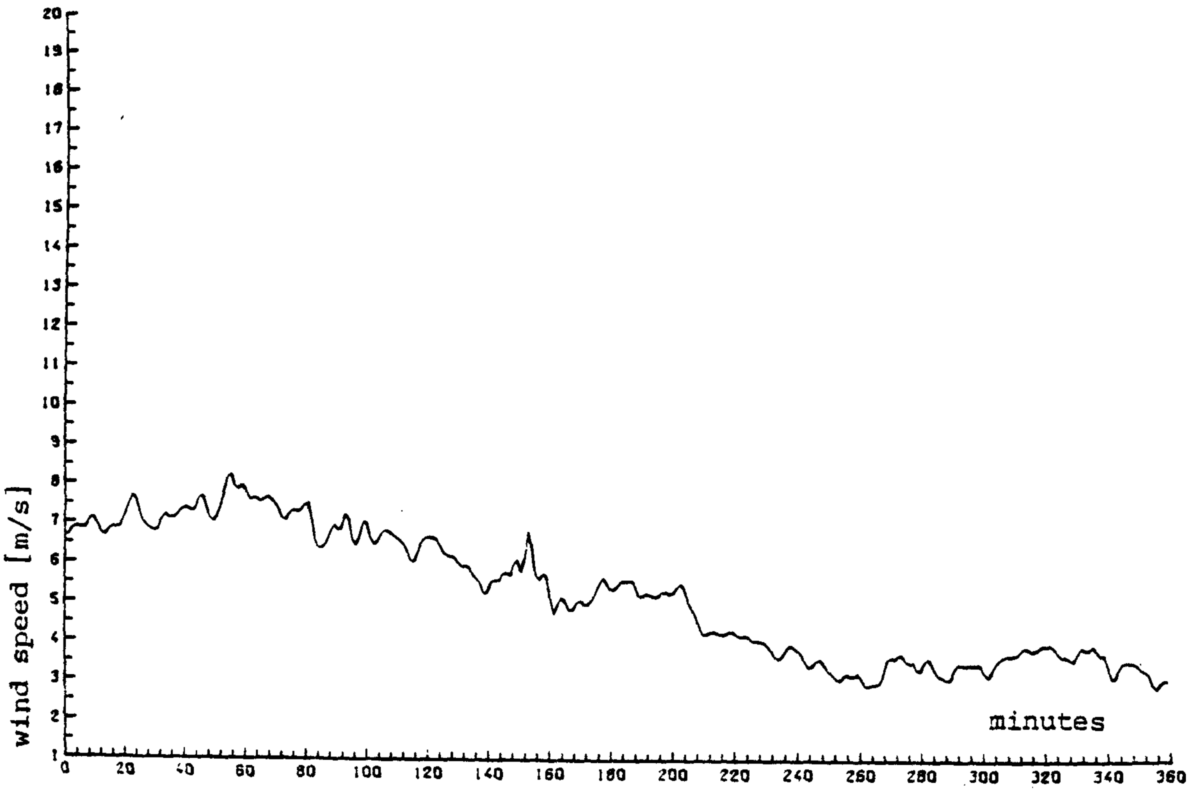

Fig. 1.3: Time series for two minute wind speed data - the stochastic process is not weakly stationary

Next, 24 ARIMA (autoregressive integrated moving average models) were fitted to the wind speed data.
Due to the time consuming nature of this kind of analysis, the analysis had to be restricted to 60 periods of each 3 hours length. If any of the 24 ARIMA-models had fitted best in most cases, accurate wind speed forecasts should be possible. None of the ARIMA-models could be said to be the significantly best model, however. This indicates that the prospects of obtaining rather accurate wind speed forecasts for periods up to 6 hours do not look good. That is, techniques have to be improved to forecast the wind speed easily and accurately.

1.1 References

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2 Wind Turbine Generation Statistics

The wind turbine output has in principal been calculated via the steady-state performance curve as shown in Fig. 2.1.

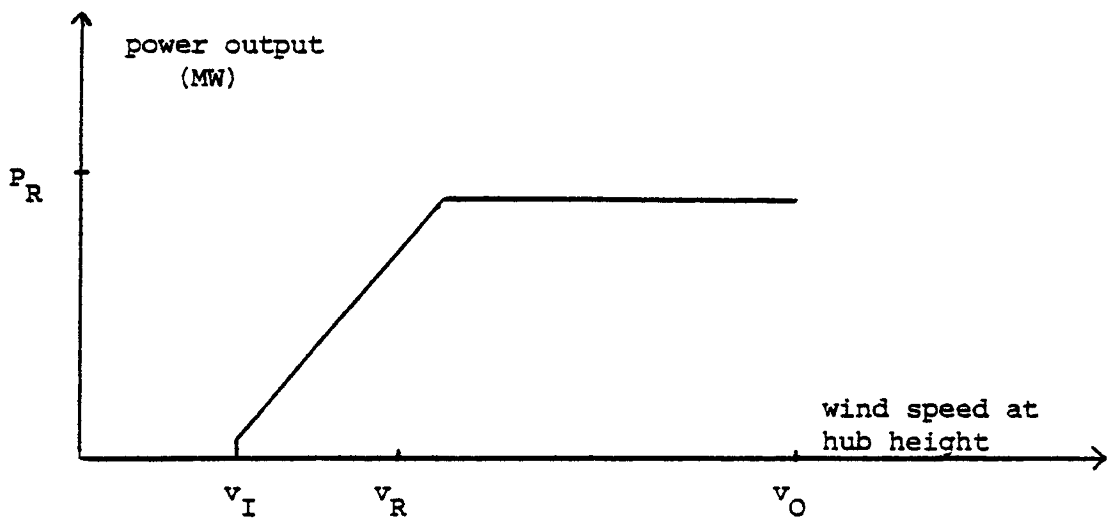

Fig.2.1: Steady-state performance curve of a wind turbine. P_R: rated power, v_I: cut-in wind speed, v_R: rated wind speed, v_O: cut-out wind speed.

Four wind turbines were modeled for the study. The relevant parameters utilized in the generation calculations are listed in Tab. 2.1. For a detailed description of the wind turbine designs the reader is referred to

[2]: Boeing MOD-2
[5]: GROWIAN
[3]: Aeolus
[7]: NIBE-A

wind turbine system	GROWIAN	Aeolus	MOD-2	0.8-MW
manufacturer	MAN-Neue Technologie	Karlstads Mekaniska Werkstad	Boeing	similar to NIBE-A wind turbine
rated power (MW)	3.0	2.0	2.5	0.8
cut-in (m/s)	6.5	6.3	6.3	6.0
rated wind speed (m/s)	12.7	13.1	12.3	12.6
cut-out (m/s)	24.0	21.0	21.0	24.0
hub height (m)	100	80	61	50

Tab.2.1: Performance parameters of wind turbines

It must be emphasized that the steady-state performance characteristic can only be expected to estimate the power output quite accurately if:

- the wind speed at hub height is representative for the wind speeds which prevail on the whole swept area,
- the mean wind speed at hub height which is used in actual calculations is representative for all the wind speeds which occur during the averaging period.

Regarding the latter, experimental data from the MOD-OA, the MOD-1 and the MOD-2 show: There is a good agreement between the actual power output of the turbine and the power output calculated from the steady-state characteristic if the turbine is synchronized over the entire time interval T [1], [9]. However, the longer T, the more a continual synchronization will fail to hold, because the wind speeds will sometimes be lower than the cut-in speed or higher than the cut-out speed. This is not considered by the mean wind speed approach of the steady-state characteristic. Recent investigations [6] show that the steady-state approach based upon mean hourly wind speeds may overestimate the power output of the wind turbine by 10 % to 20 % depending on the gustiness of the wind and the responsiveness of the turbine. The investigations were based upon two minute wind data and took into account the machine's startup, shutdown and synchronization procedure as well as its yawing behavior. Two studies [4], [9] indicate, that the usuage of non-site specific data in planning studies results in capacity factors for wind turbines larger than those observed in practice.

The bandwidth of the annual WECS power output is listed in Tab. 2.2. Note, that missing wind speeds had been rehabilitated for power output calculations. The values shown in Tab. 2.2 do, however, not account for forced outages.

The range of the intervals shown in Tab. 2.2 indicates that there is not any typical year. The corresponding intervals for shorter periods like months, days or even hours are all the larger, the shorter the period is. Therefore, the listing of those intervals or the statement of mean values can hardly claim for any substance and is omitted in this final report.

Ranking the months by the height of the mean monthly wind turbine output, the same rank order results as shown in Tab. 1.2 and Tab. 1.3 respectively. It must again be emphasized that this is only a weak tendency which did not apply for every year. Further, at most candidate sites, the wind turbine power output was higher during day-time (7 h - 19 h) than during night-time on the annual average (exceptions: Tsukubasan, Miyakejima (Japan); San Gorgonio, Ludington (USA)).

the Netherlands (1969 - 1975)	GROWIAN	0.8-MW
Cadzand (1972 - 1975)	9.1 - 12.6	2.2 - 3.0
Kornwerderzand	9.4 - 11.3	2.3 - 2.7
Terschelling	10.6 - 12.8	2.6 - 3.2
Vlissingen	5.9 - 8.8	1.3 - 2.1
Cabauw (1973)	4.8	1.0
Japan (1969 - 1975)	**GROWIAN**	**0.8-MW**
Ibukiyama	13.4 - 15.5	3.3 - 4.1
Omaezaki	10.3 - 12.0	2.1 - 2.7
Tsukubasan	9.5 - 11.4	2.0 - 2.5
Esashi	5.7 - 9.4	1.4 - 2.3
Miyakejima	8.0 - 11.0	1.8 - 2.6
Murotomisaki	11.0 - 12.5	2.2 - 2.7
Sweden (1969 - 1975)	**GROWIAN**	**Aeolus**
Malmö	8.5 - 10.1	5.2 - 6.0
Torslanda	9.0 - 11.4	5.4 - 6.8
Visby	8.5 - 10.3	5.0 - 6.1
USA	**MOD-2**	
San Gorgonio (1979)	8.1	
Ludington (11/78 - 10/79)	7.8	

Tab.2.2: Bandwidth of annual WECS power output (GWh)

On the monthly average just the opposite applied for particular months, however. Note, that the validity of the day-time - night-time results is based on the assumption, that the phenomenon shown in Fig. 1.1 does not apply for the candidate sites.

Tab. 2.3 gives the percentage of annual hours, the wind speed was either above cut-out or below cut-in. That considerable improvements can be expected through site diversity can be seen from Tab. 2.4.

the Netherlands (1969 - 1975)	GROWIAN	0.8 MW
Cadzand (1972 - 1975)	26 % - 41 %	25 % - 41 %
Kornwerderzand	30 % - 37 %	30 % - 37 %
Terschelling	26 % - 35 %	25 % - 34 %
Vlissingen	41 % - 56 %	42 % - 57 %
Cabauw (1973)	62 %	64 %
Japan (1969 - 1975)	**GROWIAN**	**0.8 MW**
Ibukiyama	21 % - 31 %	24 % - 30 %
Omaezaki	33 % - 40 %	39 % - 44 %
Tsukubasan	39 % - 46 %	40 % - 47 %
Esashi	51 % - 65 %	51 % - 65 %
Miyakejima	39 % - 48 %	34 % - 49 %
Murotomisaki	32 % - 36 %	34 % - 40 %
Sweden (1969 - 1975)	**GROWIAN**	**Aeolus**
Malmö	37 % - 46 %	37 % - 46 %
Torslanda	33 % - 43 %	30 % - 41 %
Visby	37 % - 44 %	31 % - 37 %
USA	**MOD-2**	
San Gorgonio (1979)	49 %	
Ludington (11/78 - 10/79)	40 %	

Tab.2.3: Percentage of annual hours with no WECS power output - single sites

the Netherlands	GROWIAN	0.8 MW
Cadzand + Kornwerderzand + Terschelling (1972 - 1975)	12 % - 19 %	12 % - 19 %
Japan	**GROWIAN**	**0.8 MW**
Miyakejima + Omaezaki + Tsukubasan (1969 - 1975)	8 % - 15 %	9 % - 17 %
Sweden	**GROWIAN**	**Aeoulus**
Malmö + Torslanda + Visby (1969 - 1975)	12 % - 19 %	10 % - 16 %

Tab.2.4: Percentage of annual hours with no WECS power output - diversity of sites

2.1 References

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3 Integration of Wind Turbines into the Utility Power Generation and Control System

The primary issues and concerns regarding the integration of wind electric generation into utility systems can be classified into three major categories: planning, operations and dynamic interaction.

Planning involves an assessment of the feasibility of including wind turbines in the future generation mix of the utility. This issue will be discussed in Chapter 4 and 5.

Dynamic interaction is concerned with the oscillations of power, voltage, and frequency between the wind turbines and the other generating units in the utility system. Already the conventional generation system is in a state of constant dynamic motion resulting from load changes, changes in production level at various power plants, and network switching. In general these perturbations cause excursions of power, frequency, and voltage at the system's natural frequencies of oscillation which are usually sufficiently damped to prevent a sustained system oscillation or one that grows with time. If wind turbines are added to the generation mix, the variations in wind turbine output could over-excite normal modes and could cause system instabilities. These instabilities in turn could restrict the use of wind turbines by utilities, [13]. The severity of the problem is determined from a combination of generation mix and type, load profile, and overall operational procedures. To analyse the impacts of wind turbines on dynamic interactions above all highly resolved data (milliseconds to minutes) and a confirmation of the performance of the wind turbines through actual testing is necessary. Subject to the data basis of this study such a detailed dynamic and transient analysis could not be performed. Studies examining the dynamic and stability properties of large wind turbines and impacts of large penetrations on utility systems are, e.g., [5], [7], [9], [11], [15].

Operational issues focus on the commitment of generating units with primary concern on the impact of the variable output of wind turbine arrays on the utility system, including the real-time control and the economic dispatch of both the conventional and wind turbine units. The critical issues within the operation are discussed in some greater detail within this Chapter. This Chapter is intended to serve as an guide to understanding utility system concerns, not solving them. Solutions can only be given site and utility specific, based on a much wider data basis from operating experience than gained so far.

If wind turbines are to be a significant part of an electric utility system, the primary concern regarding the operation of the intermittent resource is:

Do clusters of wind turbines necessitate the alteration of the present power system operating strategies?

System operation can be subdivided into off-line management (operation planning, unit scheduling) and on-line management (economic dispatch, frequency control, load following). Both the managements are primarily affected by the level of wind power penetration. The impact of wind power on system operation depends on the expected load share of wind power (off-line management) as well as on the actual load share of wind power (on-line management).

A number of measures for penetration such as nameplate of wind turbines as a percentage of peak demand [16], as a percentage of total installed capacity [8], as a percentage of originally-planned system conventional capacity [6] seem to be ineffective in capturing the essential factors affecting the power system operations.

3.1 Load Shares of Large Numbers of Wind Turbines

To get an impression of the actual load shares of a large number of wind turbines, hourly load data were opposed to hourly output data of wind turbine arrays. The histories of hourly load data were provided by SERI, USA; TEPCO, Japan; KEMA, the Netherlands; and Vattenfalls, Sweden.

Tab. 3.1 shows the daily load shares, 600 2.5 MW MOD-2 wind turbines, installed at San Gorgonio, CA., would have had in the Southern California Ed. (SCE) system in 1979.

Tab. 3.2 gives the mean hourly load shares of an array of 600 MOD-2's at San Gorgonio in the SCE system in 1979.

Corresponding data of other candidate sites and utilities yielded similar results.

day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1.	7.283	6.368	14.084	1.675	11.759	5.347	21.346	12.608	12.829	0.900	0.348	0.0
2.	9.207	7.016	15.719	9.867	19.931	0.435	19.994	10.026	6.641	0.0	0.0	0.0
3.	0.0	0.0	0.0	1.047	10.936	6.496	17.471	12.891	19.720	2.496	6.986	0.203
4.	0.0	0.232	0.277	0.0	3.910	19.139	15.810	9.658	12.033	4.649	19.573	2.928
5.	0.0	0.329	0.125	1.351	18.758	16.703	16.927	5.798	2.922	7.734	1.681	2.947
6.	0.0	0.0	0.642	18.265	16.976	12.827	16.333	8.212	0.666	9.427	0.0	0.0
7.	0.0	0.0	0.0	16.369	8.971	2.936	11.124	8.179	0.137	15.327	6.076	0.0
8.	0.032	0.136	2.402	23.232	18.990	5.221	9.953	12.291	0.230	17.613	17.877	0.0
9.	1.025	0.744	0.269	11.091	18.940	0.108	10.792	9.436	0.0	2.372	17.036	0.971
10.	0.0	2.459	0.622	19.449	5.106	5.438	17.555	12.207	0.388	3.683	1.107	10.297
11.	0.0	0.0	2.163	19.728	0.235	16.653	17.397	9.936	2.355	13.427	1.117	12.049
12.	15.754	0.0	18.379	1.924	1.718	4.727	3.314	6.239	0.726	14.871	3.123	1.328
13.	0.972	5.096	12.277	3.173	0.441	6.376	0.206	10.677	0.335	17.492	2.552	0.088
14.	1.612	18.050	7.329	4.752	5.264	12.714	1.611	9.447	0.098	22.561	1.926	0.770
15.	0.0	9.027	17.730	7.901	9.133	12.127	3.924	5.598	0.595	14.416	1.921	0.874
16.	0.0	19.916	19.819	10.543	7.538	7.902	1.770	9.507	0.0	8.179	1.983	0.171
17.	0.0	2.674	8.124	13.554	0.191	7.315	4.759	16.970	0.0	11.854	17.022	2.457
18.	8.472	0.179	7.791	19.656	0.196	19.536	2.267	17.622	0.0	14.691	20.485	0.0
19.	3.523	19.203	2.310	3.473	5.212	5.572	0.797	16.969	0.676	12.150	4.817	0.0
20.	0.0	14.347	0.599	3.453	10.925	7.331	0.371	10.546	2.662	20.054	2.934	9.454
21.	1.178	18.007	15.121	6.458	12.219	13.870	4.058	9.365	4.288	11.818	1.615	18.045
22.	16.124	17.416	8.568	19.639	2.498	13.198	12.678	5.439	8.428	0.170	0.082	19.572
23.	0.305	17.396	0.0	20.173	7.328	6.934	3.491	8.981	1.568	0.403	3.086	2.130
24.	0.0	0.111	4.324	19.729	17.998	6.602	8.282	15.945	1.081	1.148	0.0	0.0
25.	4.084	0.0	16.074	13.479	4.524	14.391	12.617	16.231	8.456	5.096	0.0	0.635
26.	3.563	19.276	18.040	18.869	6.141	8.712	10.926	15.743	10.212	14.986	0.577	7.420
27.	0.194	5.858	6.733	17.646	12.210	3.747	12.663	1.295	11.828	3.277	5.206	0.348
28.	1.819	5.037	13.195	16.734	24.135	6.223	9.392	8.128	6.259	18.230	5.619	1.328
29.	0.050	----	19.763	15.847	18.014	10.918	6.023	17.407	6.301	5.327	2.232	0.269
30.	0.0	----	17.400	13.237	13.734	17.930	9.462	14.786	4.572	0.876	0.261	0.0
31.	0.0	----	1.668	----	2.941	----	3.129	14.929	----	0.123	----	0.0

Tab. 3.1: Daily load shares of 600 2.5 MW wind turbines at San Gorgonio in 1979 in %. Load reference data: SCE load of 1979. Forced outages of the wind turbines were taken into account by reducing the WECS production by 8%.

HOUR	JAN	FEB	MAR	APR	MAI	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ROW MEAN
1	1,64	9,06	11,23	16,07	12,42	14,23	14,99	15,74	5,61	11,70	5,67	3,80	10.19
2	1,65	9,08	11,29	15,29	12,72	14,11	14,61	16,97	5,70	10,90	5,91	3,75	10.25
3	2,14	9,55	11,21	12,80	12,71	12,32	13,27	10,33	5,62	9,74	6,53	4,04	9.92
4	2,53	8,75	10,99	14,16	9,33	11,48	11,61	17,14	4,35	11,23	6,23	4,56	9.37
5	2,39	8,03	10,38	11,47	9,72	10,27	10,79	14,92	5,31	10,22	6,16	3,92	8.70
6	2,28	7,77	9,11	10,16	9,10	8,07	8,53	10,39	3,73	9,77	6,02	2,97	7.46
7	2,43	6,38	7,56	8,01	7,64	5,00	5,79	5,71	2,61	7,79	6,15	2,78	5.65
8	1,95	5,60	4,87	7,81	6,19	3,36	4,59	5,23	1,85	7,65	5,25	2,09	4.70
9	2,19	4,80	5,03	9,19	5,52	4,29	4,28	5,30	1,54	6,42	4,48	2,03	4.61
10	2,58	4,46	5,16	9,35	5,09	4,60	5,31	6,85	1,85	5,94	3,49	2,51	4.77
11	2,44	4,61	5,92	9,34	5,55	3,99	4,66	6,12	1,89	6,17	3,01	2,54	4.69
12	3,06	4,91	6,80	9,96	5,70	3,29	4,29	5,62	1,68	6,39	3,24	3,27	4.85
13	2,87	5,32	6,89	9,94	5,49	3,28	5,30	5,60	1,77	6,87	3,54	3,64	5.04
14	3,09	5,50	7,46	10,14	6,69	3,75	6,29	6,60	2,19	6,47	3,35	3,61	5.43
15	3,59	5,57	7,72	10,97	6,42	4,69	7,06	8,10	2,97	7,39	3,85	3,37	5.95
16	3,51	6,07	8,44	11,27	7,44	6,14	8,29	9,88	3,61	7,92	4,37	3,28	6.65
17	2,74	6,36	9,31	11,92	10,55	7,75	9,42	11,36	4,64	7,95	4,83	2,82	7.43
18	1,60	6,16	8,76	12,63	12,47	11,32	9,92	12,77	4,81	8,77	4,66	2,04	8.00
19	1,66	6,10	7,54	12,46	13,59	13,32	11,58	14,25	6,22	10,00	4,55	2,34	8.65
20	1,69	6,85	7,14	12,61	13,69	14,50	13,33	14,31	6,36	10,31	4,70	2,19	8.98
21	1,93	6,69	7,80	12,90	12,13	14,03	12,02	13,91	6,60	10,70	4,95	2,66	8.87
22	1,74	6,40	8,02	13,20	11,90	15,41	13,28	14,17	6,79	11,25	5,27	2,80	9.21
23	1,52	7,67	9,49	15,23	11,96	15,02	13,88	13,16	5,44	11,70	5,83	2,59	9.53
24	1,89	7,95	10,10	15,72	13,52	16,65	13,98	13,39	4,72	11,93	6,21	3,48	9.97
COLUMN MEAN	2,33	6,72	8,26	11,78	9,48	9,27	9,46	11,08	4,07	8,97	4,96	3,05	7.46

Tab. 3.2: Mean hourly load shares of 600 2.5 MW wind turbines at San Gorgonio in 1979 in %. Load reference data: SCE load of 1979. Forced outages of the wind turbines were taken into account by reducing the WECS production by 8%.

The load shares listed in Tab. 3.1 and Tab. 3.2 demonstrate the stochastic nature of wind power. The daily load shares change from day to day and, above all, the changes do not show any regularity. Considering shorter periods like hours, minutes or seconds, both the variations and their lack of regularity become even more pronounced. This indicates that a large number of wind turbines can have a significant impact on the current operations of the utility system such as excessive ramping of the conventional units and unacceptable regulation work. Some of these impacts may require modifications of the current operating strategy which is sketched below.

3.2 Operational Concept Of A Power System

The present utility system operation consists of two phases - the operation planning and the real time operation. The operation planning is an off-line procedure that involves the commitment of generation units to be operated for each hourly segment of the next day. The real time operation involves the on-line management and control of the generation units, [14].

3.2.1 Operation Planning

The operation planning process involves the scheduling of the generation to meet the load. Input are peak load forecasts of all the hours of the next day. The various forecast techniques employed are based on analysis of historical load data, evaluation of recent daily load trends and, of course, on weather forecasts. The load forecast can be given quite accurately. According to [4], the mean deviation from the actual load is within the West German intertie:

forecast for the next 24 hours : $\pm$ 3 %
forecast for the next year : $\pm$ 5 %
forecast for the third to fifth year: $\pm$ 6 %

The cyclic variations in load require the capability to cycle generating units such that a high quality of electricity is maintained, i.e., proper frequency and sufficient capacity.

With regard to their capability to follow the temporal requirements of the load both in magnitude and rate of change, the generating units are classified in base, intermediate and peak load units. For an extensive discussion of the unit characteristics and unit operating constraints, the reader is referred to the reports for the participating countries.

3.2.1.1 Reserve Capacity

In order to guarantee a safe power supply during real time operation extra generation is scheduled as reserve capacity. The reserve capacity is needed for:

- outage of units, maintenance of units, lack of cooling possibilities, variations in run-of-river supply, outage of exchange power,
- regulation and control.

That is, reserve is necessary both for generation failures and undisturbed operation (frequency control).

The reserve is generally classified in spinning reserve and standby capacity.

The reserve is scheduled both with regard to its capacity and its access time. Fig. 3.1 illustrates the reserve requirements.

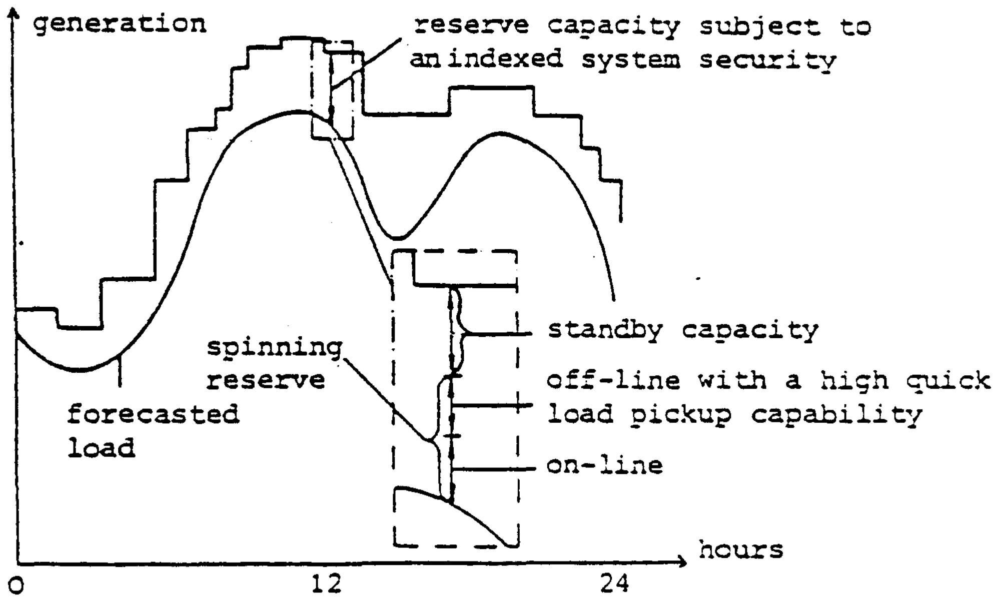


Fig.3.1: Reserve capacity and load

3.2.1.2 Unit Scheduling

The actual collection of units is scheduled on an hourly basis to meet the forecasted load at minimum production costs. Constraints are given by the unit characteristics, the unit operating costs, the unit operating constraints, and the system operating constraints. A result of unit scheduling is a time table indicating which types of units for what time span are put on and/or taken off line for the next 24 hours. As the production costs are determined by the fuel costs and the cycling costs, the objective function can be quantified as follows:

$$c_p = \int_0^T \sum_{i=1}^{n} (c_{f_i}(p_i(t)) + c_{c_i}(t))dt \rightarrow \min! \qquad (3.1)$$

where

T : period for the cost minimization (usually a period of 24 hours)

$c_{f_i}(\ )$: fuel costs as a function of time and power level for the i-th unit

$c_{c_i}(\ )$: cycling costs for the i-th unit

c_p : production costs

3.2.2 REAL TIME OPERATION

Based upon the schedule of the operation planning, a more detailed dispatch of the generation is required. For that purpose, economic dispatch of the firm system load above baseload is performed almost continuously.

The dispatch is made subject to the lowest incremental production cost. This on-line management is performed to continuously adjust the system generation to the system load.

In the present day practice both the generating units and the loads are connected to a multiple-area interconnected system in order to obtain both continuity of service to customers and the most economical power production.

A multiple-area interconnected system consists of operating areas (i=1, ..., n), each one of which is expected to adjust its own generation in order to absorb its own load changes and unit failures.

The continuous load changes, the changes in production level at units, and outages result in a continual generation change (jumps, ramps, ups and downs). These load/generation changes are reflected in frequency variations.

The system frequency and the generation is monitored by the combined actions of the generator frequency control and the automatic generation control (AGC) of an operating area.

The AGC monitors the total area deviation in frequency (Δf) plus the net tie line power flow deviation (ΔP_{tie}) of the i-th operating area. The deviation is measured as the area control error (ACE):

$$\text{(3.2)} \qquad ACE = \Delta f + \Delta P_{tie}$$

To null the ACE and to adapt the generation to the load, three factors gain interest, [11], [14]:

<u>Spinning reserve</u> is defined as the difference between the total capacity of all synchronized units assigned to regulation and the actual load on those units.

<u>Unloadable generation</u> is the difference between the load on the regulating units and the minimum load that can be placed on the units.

The <u>load following capability</u> is the maximum change in generation due to regulation and economic dispatch combined.

In general, spinning reserve must be sufficient to follow the maximum probable increase in generation required in ten minutes. Without wind generation, the maximum probable increase in conventional generation over a ten minute period is given by:

The loss of the utility's largest generating unit or tie line power import, plus the maximum increase in load.

Similarly, sufficient unloadable generation must be made available to follow the maximum probable decrease in generation, which is given by:

The loss of the utility's largest load or tie line power export, plus the maximum decrease in load.

In Fig. 3.2 the requirements are sketched, [14]:

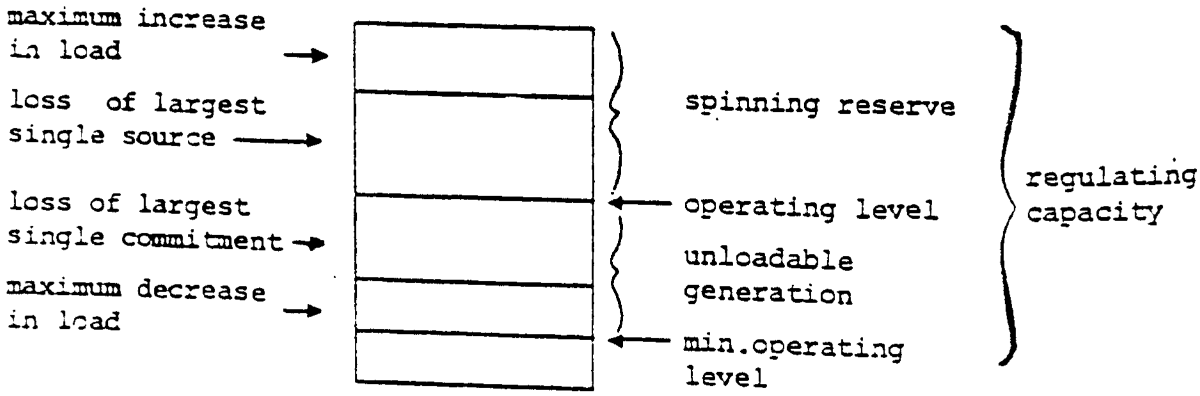


Fig. 3.2: Regulating capacity requirements for AGC of the conventional generation

3.3 Wind Turbines and the Negative Load Concept

As for all the electric utility systems, a wind-assisted system is mandated to operate at minimum cost with a prescribed level of reliability.

As wind energy is a primary energy free of charge, it would in principle be favorable to let the wind turbines generate as much electricity as possible. However, since start and stop procedures for the large nuclear and/or fossil fired units are undesirable from a technical and economic point of view, the base load units are kept on-line, even if wind power had allowed the shutdown of some of these units. Ranked inferior to the base load units, wind power is committed superior to all other conventional units but the regulating units. Because the wind is available intermittently, wind turbines cannot be dispatched to meet a sudden load change or a crisis due to a failure of a generating unit. Hence, wind turbines cannot be committed as regulating units.

The residual load (total system load less the net generation of the base load units less the net generation of the wind turbines) is then input to an iterative search to determine the least cost choice of units according to equation (3.1). This approach is referred to as negative load concept.

Hence following, wind power competes in displacing the power output of the cycling economic dispatch and peak load units. These units are generally fueled by oil or coal.

Fig. 3.3 illustrates the load matching process in the presence of wind power.

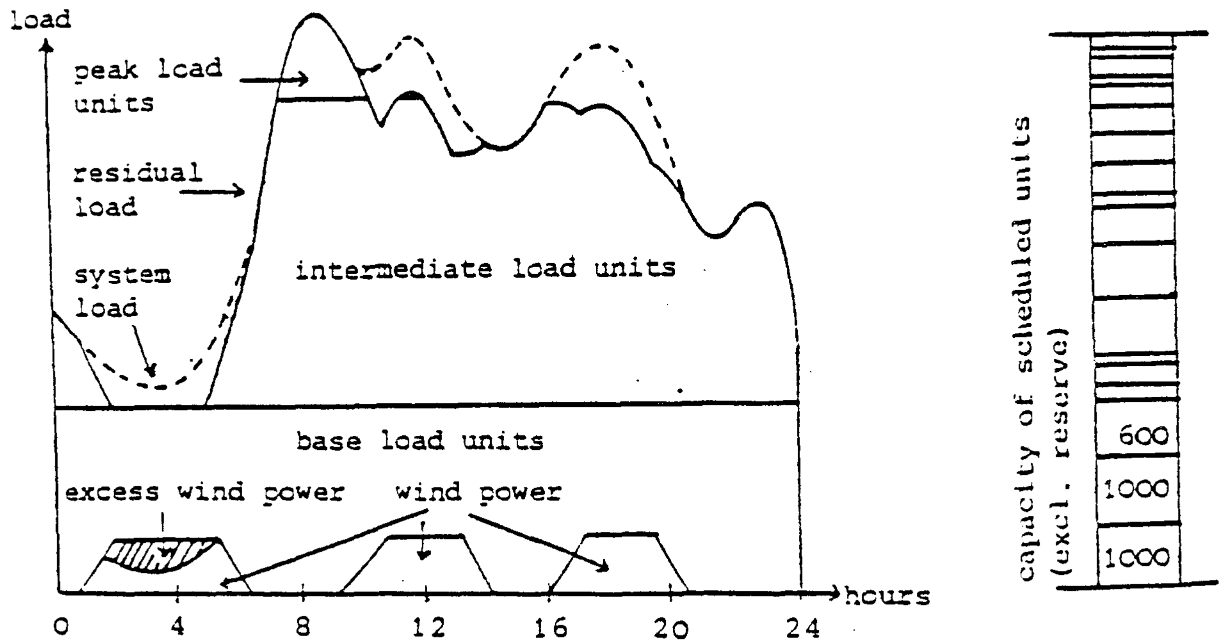


Fig.3.3: Load profile, wind contribution and the allocation of the conventional units to meet the load

To which extent conventional fuels are displaced, depends on

- the penetration level of the wind turbines
- the wind regime and the wind park configuration
- the wind turbine generators
- the system operating strategy
- the accuracy of the wind turbine output forecast.

3.3.1 VARIABILITY OF WIND POWER

The unit scheduling is generally programmed on an hourly basis. The variability of hourly wind power is therefore of major concern for the operation planning.

In Fig. 3.4 the hourly output, 1.830 Aeolus wind turbines would have produced in March 1975 is plotted against the hourly Swedish load of March 1975.

In Fig. 3.5 the hourly output, 900 GROWIAN 3.0 MW wind turbines would have produced in March 1975 is plotted against the hourly Dutch load of March 1975.

Finally, in Fig. 3.6 the hourly output of 1.800 GROWIAN 3.0 wind turbines is opposed to the hourly load of TEPCO of December 1980. The output remained constant over the interval [1 h, 3 h], [4 h, 6 h], ..., [22 h, 24 h]. This is due to the fact that the wind data we received were mean wind speeds with averaging times of three hours (see Chapter 1).

For corresponding plots of other months the reader is referred to the reports for the Participants.

As can be inferred from the plots, the power output varies considerably from hour to hour. As for Japan, the load shares of hours from successive intervals differ to a large extent. However, it is not this fact which makes a smooth integration doubtful but the lack of regularity in the variations. The load, for example varies too, but the variations show a high degree of regularity, as indicated in Fig. 3.4 through Fig. 3.6

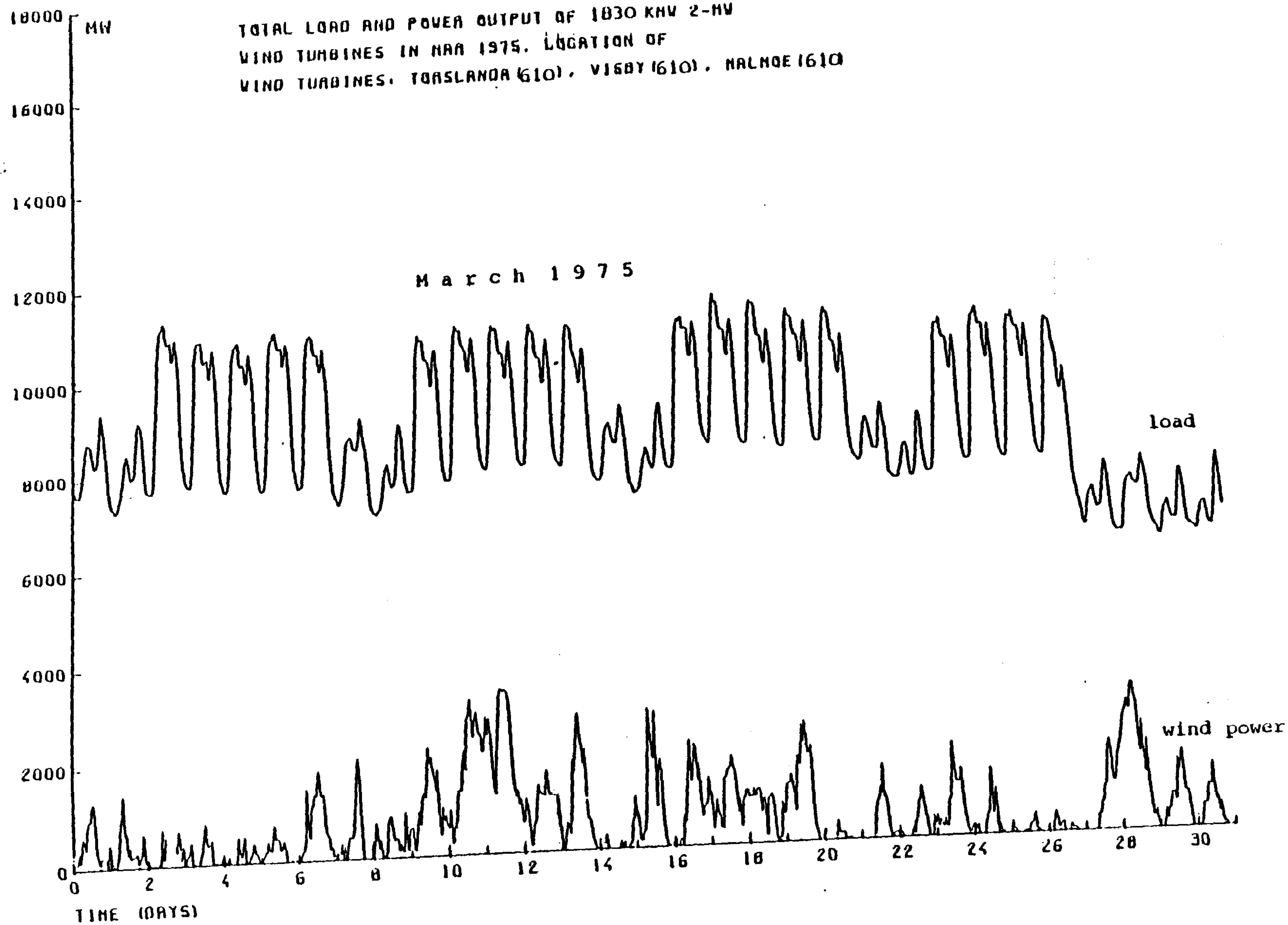


Fig.3.4: Swedish load pattern and wind generation in March 1975

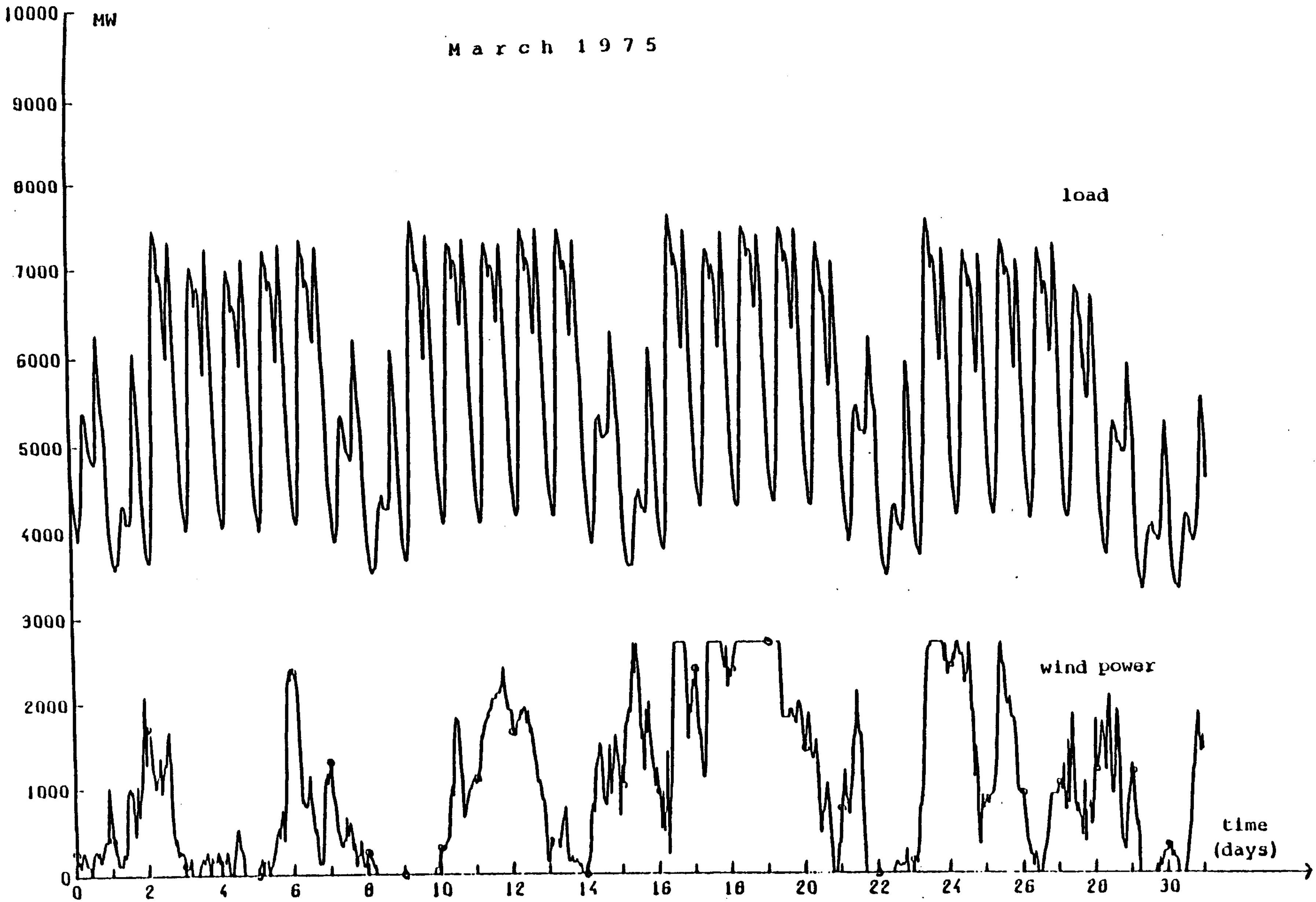


Fig.3.5: Load and generation of 900 3-MW wind turbines in March 1975. Location of wind turbines (number of wind turbines): Cadzand (300), Kornwerderzand (300), Terschelling (300).

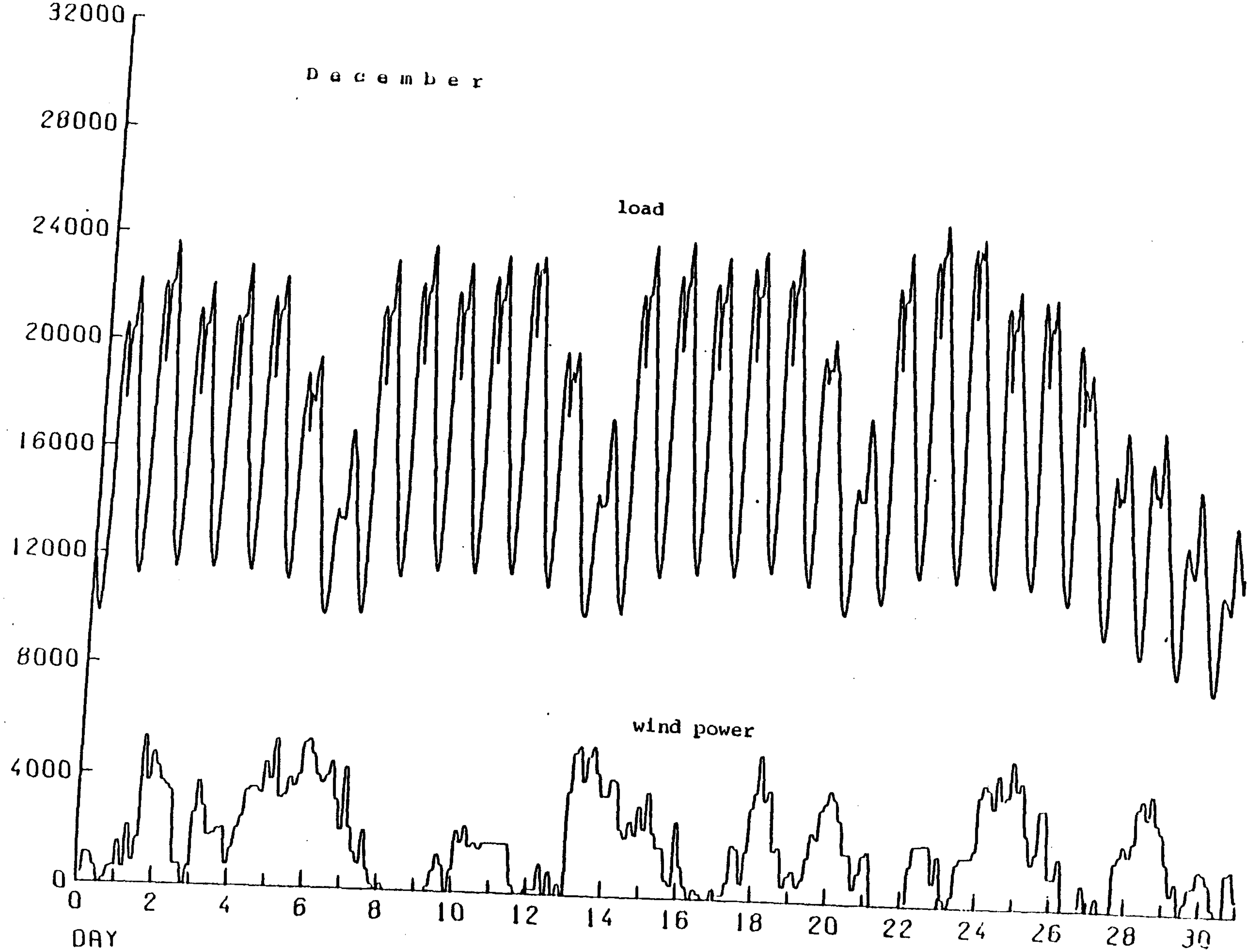


Fig.3.6: TEPCO load of December 1980 versus the power output of 1800 3.0 MW wind turbines. Power output of wind turbines calculated from wind speed data of December 1974. Geographical dispersal of sites (number of wind turbines): Omaezaki (600), Miyakejima (600), Tsukubasan (600).

In order to assess the effects of the wind power output variability on the present-day operation planning concept, a hypothetical perfect wind turbine output forecast is assumed in the following. The investigations are confined to the ups and downs in wind generation within the next three hours, [3].

Let Y_t be the hourly wind turbine power output. Then the maximum relative variation in output from hour t to t+i is given by expression (3.3), subject to the condition that there is a wind turbine output unequal to zero in the hour t:

$$(3.3) \quad d_{t+i} := \max \left\{ \left|\frac{Y_t - Y_{t+1}}{Y_t}\right|, \ldots, \left|\frac{Y_t - Y_{t+i}}{Y_t}\right| \right\} \quad i=1,2,3$$

where Y_{t+j}: hourly wind turbine output in the hour t+j (j=0,1,...,i)

d_{t+i}: max. relative variation within the period (t, t+i)

Tab. 3.3 shows the frequency distribution for categories of maximum variations in wind power output for the two sites San Gorgonio and Ludington, USA. If a significant WECS level exists, it is assumed that variations in the category of

- [0 % - 20 %] are negligible for the unit commitment,
- (20 % - 50 %] are absorbable under alterations of the regulating capacity,
- (50 % - 80 %] require more pronounced reserve capacity schedules,
- (> 80 %) require commitment and dispatch alterations to a larger extent.

	categories of variation			
	[0%-10%]	(10%-20%]	(20%-30%]	(30%-50%]
time horizons:	t+1/t+2/t+3	t+1/t+2/t+3	t+1/t+2/t+3	t+1/t+2/t+3
Ludington				
1/1/79-10/31/79	40.3/25.2/19.5*	15.4/12.4/10.0	10.2/10.8/8.9	11.8/15.2/15.4
San Gorgonio				
1/1/79-12/31/79	52.3/40.4/35.0	10.5/ 8.6/ 7.0	7.4/ 7.3/6.7	8.8/11.3/11.2
	categories of variation			
	(50%-70%]	(70%-80%]	(80%-90%]	(> 90%)
time horizons:	t+1/t+2/t+3	t+1/t+2/t+3	t+1/t+2/t+3	t+1/t+2/t+3
Ludington				
1/1/79-10/31/79	6.3/ 8.5/10.3	2.0/ 3.5/ 4.3	1.0/ 2.1/2.6	13.1/22.3/29.0
San Gorgonio				
1/1/79-12/31/79	4.5/ 6.1/ 6.0	1.8/ 2.5/ 3.0	0.9/ 1.4/1.9	13.8/22.6/29.3

Tab.3.3: Frequency distribution for categories of maximum wind power variations for different time horizons
*The relative frequency is 19.5 that within a period of three hours the relative maximum variation of the hourly power output of a 2.5 MW MOD 2 wind turbine is within the category [0%-10%].

The following conclusions can be drawn from Tab. 3.3 :

The longer the time horizon, the more the variations exceed the range of [0 % - 10 %] and (10 % - 20 %]. Coincidently, it becomes more likely that variations in the range of (> 70 %) occur. Above all the increases in frequencies for variations exceeding 90 % is significant.

To take into account a geographical dispersal of the wind turbine arrays, results for the Netherlands and Sweden are presented in Tab. 3.4 and Tab. 3.5.

From Tab. 3.4 and Tab. 3.5 it may be concluded that a diversity of wind generation will likely smooth the variations. That is, the frequencies being part of the categories (0 % - 10 %] and (> 90 %) decrease. This decrease coincides with higher frequencies of the categories (10 % - 50 %] and (50 % - 90 %], indicating that extrem low or extrem high changes are less probable.

The values of Tab. 3.3 through Tab. 3.5 are based on a wind turbine generation in the hour t. In addition, the behavior of the wind turbine output after an hour of standstill gains interest. In this context, the wind turbine is at standstill if the hourly mean wind speed either exceeds the cut-out speed or is below the cut-in speed of the turbine. The increase is measured as:

	categories of variation			
	[0%-10%]	(10%-50%]	(50%-90%]	(> 90 %)
time horizons:	t+1/t+2/t+3			
Terschelling				
1971	43/28/22*	33/35/30	12/16/20	12/21/27
1972	46/32/26	30/29/26	11/16/19	14/23/29
1973	45/31/25	29/29/26	11/16/18	14/24/31
1974	48/33/28	30/31/28	10/16/18	12/20/26
1975	48/34/28	29/28/25	11/16/19	13/22/28
Kornwerderzand				
1971	41/27/21	30/29/26	12/17/19	16/27/34
1972	43/29/24	29/29/25	12/17/18	17/26/32
1973	39/25/20	29/28/23	14/19/21	18/29/36
1974	43/28/22	30/31/28	11/17/20	15/24/31
1975	43/28/22	29/29/25	11/16/18	17/27/34
Netherland-Compound				
1971	39/24/18	37/39/35	11/17/20	12/21/27
1972	40/26/21	35/34/30	11/17/20	14/22/29
1973	37/22/17	36/35/31	12/18/21	15/25/32
1974	42/26/19	37/38/35	10/17/20	11/19/26
1975	41/27/21	34/34/31	11/17/19	13/23/29

Tab.3.4: Frequeny distribution for categories of maximum WECS power output variations in different time horizons (the Netherlands)

*The relative frequency is 22 % that within a period of three hours the relative maximum variation of the hourly power output of the Aeolus wind turbine is within the category [0%-10%]

	categories of variation [0%-10%]	(10%-50%]	(50%-90%]	(> 90%)
time horizons:	t+1/t+2/t+3			
Torslanda				
1971	50/32/23*	14/16/15	14/18/18	23/35/43
1972	47/28/19	14/16/15	13/18/19	26/39/47
1973	48/30/22	13/14/13	13/17/18	26/39/47
1974	45/27/20	15/16/15	14/18/19	26/39/46
1975	46/28/21	13/14/13	15/18/19	26/39/48
Malmö				
1971	46/27/18	15/17/15	17/23/26	22/23/41
1972	45/26/18	16/19/17	16/21/23	23/34/42
1973	45/25/17	17/18/17	16/21/23	23/36/44
1974	46/27/19	17/19/18	17/22/24	21/32/39
1975	46/27/19	16/17/15	16/22/24	23/34/42
Sweden-Compound				
1971	34/16/10	34/37/33	15/21/23	17/27/35
1972	35/16/10	32/33/30	14/21/23	20/30/37
1973	34/16/ 9	32/34/32	15/20/23	19/30/37
1974	33/15/ 9	35/37/34	14/20/23	18/28/35
1975	34/16/ 9	32/33/30	16/22/24	19/29/36

Tab.3.5: Frequency distributions for categories of maximum WECS power output variations in different time horizons (Sweden)
*The relative frequency is 23 % that within a period of three hours the relative maximum variation of the hourly power output of the Aeolus is within the category [0%-10%]

$$(3.4) \qquad d_{t+1} := \{|Y_t - Y_{t+1}|\}$$

where d_{t+1}: increase in wind turbine generation from the hour of standstill t to the hour t+1

In Tab. 3.6 the frequency distribution for the two US-candidate sites is recorded.

output ranges	San Gorgonio 1/1/79-12/31/79	Ludington 1/1/79-10/31/79
[0.0-0.5 MW]	95.0	96.2
(0.5-1.0 MW]	3.0	2.7
(1.0-1.5 MW]	1.1	0.4
(1.5-2.0 MW]	0.3	0.1
[2.0-2.5 MW]	0.6	0.6

Tab.3.6: Frequency distribution for categories of WECS power output after standstill; WECS: MOD-2

In Tab. 3.7 and 3.8 a compound of the two Dutch and two Swedish sites, listed in Tab. 3.4 and Tab. 3.5 respectively, is regarded.

output ranges	year				
	1971	1972	1973	1974	1975
[0.0-0.5 MW]	99.0	99.5	98.8	98.9	99.2
(0.5-1.5 MW]	1.0	0.5	1.2	1.1	0.7
(1.5-2.0 MW]	0.0	0.0	0.0	0.0	0.1

Tab.3.7 : Frequency distribution for categories of WECS power output after standstill (Sweden); WECS: Aeolus

output ranges	year				
	1971	1972	1973	1974	1975
[0.0–0.5 MW]	99.4	99.0	99.0	98.7	99.0
(0.5–1.5 MW]	0.5	0.8	0.9	1.1	0.7
(1.5–2.0 MW]	0.1	0.2	0.1	0.2	0.3

Tab. 3.8: Frequency distribution for categories of WECS power output after standstill (the Netherlands); WECS: Aeolus

Conclusion: It is most important that the increase within one hour in wind turbine output after an hour of standstill is predominantly in the half-megawatt range. This result holds for the compounds as well as for the single sites. It can be inferred from Tab. 3.6 through Tab. 3.8 that it is not that likely that jumps from no generation to rated generation occur.

3.3.2 Effects of Wind Turbine Parks on Operation Planning

For a system including a significant number of wind turbines, it may be inferred: Even if there were a perfect wind power forecast, the scheduled regulating capacity has to be increased in order to compensate for the significant changes in wind turbine output from one hour to the other.

For example, Tab. 3.3 indicates that the frequency is about 36 % (Ludington)/33 % (San Gorgonio) that the max. variations within 2 hours exceed 50 %, and about 46 % (Ludington)/40 % (San Gorgonio) that the max. variations within 3 hours exceed 50 %.

However, it can be concluded from Tab. 3.6 through Tab. 3.8 that after standstill of the turbine, the increase in power output is very slow. Abrupt jumps to rated power occur only during very few hours in the year. It may be inferred that operation planning should be able to rely on the fact that the WECS power output does not enter the grid explosively.

Furthermore, a geographical dispersal of the parks is likely to smooth the variations in mean hourly wind generation, as shown in Tab. 3.4 and Tab. 3.5. However, the diversified siting cannot neutralize the variations.

As long as the negative load concept is applied, the midterm variations in wind generation will impact the unit commitment, if a significant number of wind turbines is installed.

An increase in regulating capacity necessitates an alteration of the unit scheduling process. In addition to an increased schedule of gas turbines, hydroelectric, and stored hydro, a larger number of cycling units will have to be operated part-loaded. This increase in loading and in capacity for units scheduled for regulating duty will be accompanied by a decrease in loading and in capacity of economic dispatch units. Hence, the revised scheduling of conventional units will result in increased production costs. This cost increase must be applied against the value of wind generation.

Note, the investigations of the variations of wind generation were based upon perfect output forecasts. So far, only little work has been done on the field of forecasting wind turbine output.

If reliable anticipatory information about wind speeds which will be used to predict wind turbine output is available, the following advantages are offered:

Thermal units could be shutdown in time or they need not be put on line if wind generation is said to be available in three hours, for example. On the other hand, thermal units can be started up in advance in order to be on line, if the wind generation is expected to decrease. Based upon this in advance knowledge, the economic dispatch units could partially be preferred to the regulating units in the commitment. Compared to a scheduling without anticipatory wind information a more efficient employment of the cycling units results.

For that very purpose, wind speed forecasts of equal length with the startup times from spinning and non-spinning state of cycling thermal units are required, [2].

With regard to a system favorable to wind power (Sweden: large spinning reserve (hydro)), the following permissible root mean square errors of a wind speed forecast were suggested by utilities for a wind penetration of 10 %, [12]:

RMSE	projection time of wind speed forecasts
± 1.0 m/s	< 4 hrs
± 1.5 m/s	4-10 hrs
± 2.0 m/s	>10 hrs

A Swedish study [1] investigating the present-day meteorological wind forecast methods, concluded that none of the current forecast methods meets the rather stringent requirements. Furthermore, the results of time series analyses which were sketched in Chapter 1, indicate that time series methods may also fail to give forecasts of the required accuracy.

Conclusion: To date, the prospects of good wind power forecasts are gloomy. Operation planning will thus have to rely on increased regulating capacity, if a significant wind penetration is implemented.

3.3.3 EFFECTS OF WIND TURBINE PARKS ON REAL TIME OPERATIONS

Fig. 3.7 shows the power output of the Danish Nibe-A wind turbine within 12 minutes at August 24th, 1980.

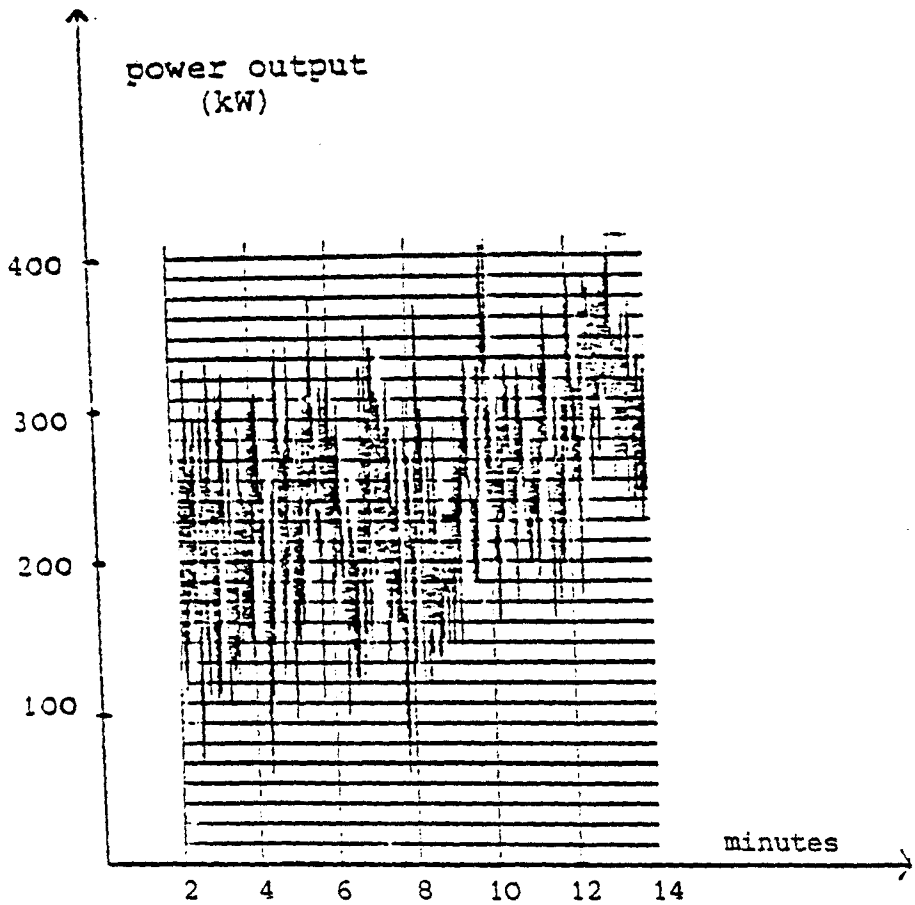


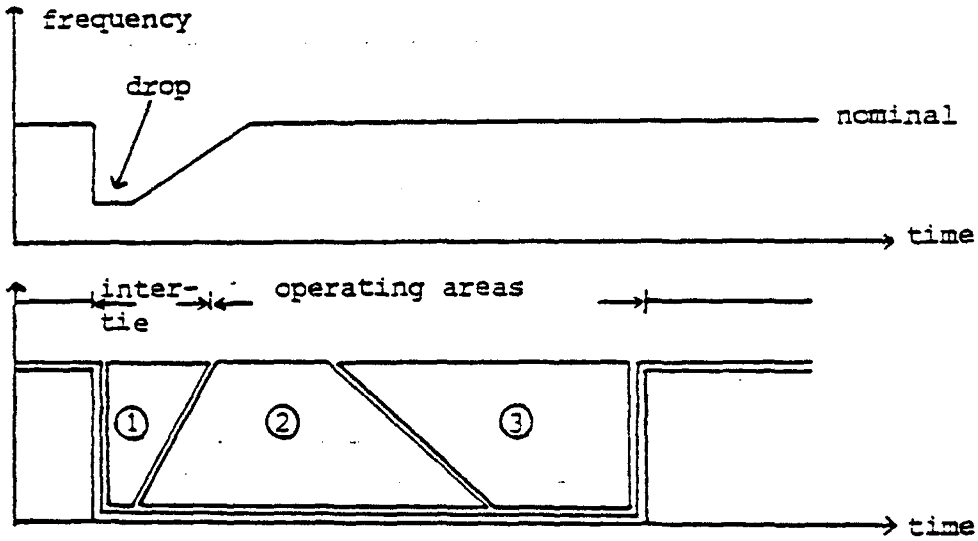
Fig. 3.7: power output of the Danish Nibe-A wind turbine within a twelve minute period.

The variations in output require the capability of the system to restrict to the variations within acceptable limits. Thus, the conventional generation mix must have sufficient response capability to follow the midterm variations of wind power both in magnitude and rate of change and to compensate the shortterm variations. Some indications may, therefore, be given if wind power is integrated on a higher penetration level:

- the load following capability need to be enlarged,
- the spinning reserve will have to be increased by an amount equal to the maximum probable decrease in wind generation over a period of several minutes,
- the unloadable generation will have to be increased by an amount equal to the maximum probable increase in wind generation over a period of several minutes.

In the case that the load following capability is exceeded, excessive frequency deviations, and ACE excursions may occur. The implications of excessive frequency deviations and ACE excursions are increased fuel consumption, increased wear on regulating units, and violations of interchange agreements.

To restrict (negative) frequency deviations to within acceptable limits, which guarantee a high quality of electricity, a sequence of responses exists. The conceptual scheme of the control concept is shown below:



means: ① natural governor action
proportional regulation
system intertie, rotating masses

② spinning reserve
exchange power
economic dispatch

③ standby capacity
contractual power
unit commitment and economic dispatch

Conclusion: All these measures require that sufficient load following capacity is scheduled on line and that the system is provided with sufficient load following capability. To secure system operation one might suggest to simply increase the system load following capability, if the wind turbine penetration is increased. However, simply increasing the load following capability is not an attractive means, since it would further increase the tendency to shift load from efficient economic dispatch units to less efficient regulating units. Increasing spinning reserve, standby capacity and unloadable generation would incur additional costs and would increase the production costs. The production cost increase would reduce the economic benefits derived from wind generation.

Finally, a statement must be made with regard to the smoothing effect of the power output, which is supposed to occur if a large number of wind turbines is installed over a widespread area. Sometimes studies give the impression, that this smoothing of the overall wind generation is the most valuable means to avoid penetration constraints.

Statistical methods indicate that a smoothing effect can be expected if time periods are considered and if the smoothing effect is measured by the mean or total wind power output of the period related to the variance. This knowledge may be useful in the off-line planning of reserve capacity.

However, as each change in wind power output would - ceteris paribus - be followed instantaneously by proportional and/or supplementary regulation and control (on-line management) nothing can be deduced from the smoothing effect with regard to the real time system operation, [10].

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4. Displacement of Conventional Capacity by Wind Turbines

Wind turbines are said to have a capacity credit if they can displace the installation of conventional units (thermal units (including nuclear units) and hydro units). The displacement must be subject to the condition that the system reliability is maintained. This means that a generation mix composed of wind turbines and conventional units must guarantee a power supply with the same degree of reliability as would do a power plant mix merely composed of conventional units.

Utilities often doubt whether that is possible at all by arguing that they cannot control the wind power. The wind is blowing whenever the wind wants to blow and the wind is not necessarily blowing when the utility wants him to blow.

These problems fade if wind power is being stored. We shall, however, see Section 5.1, assume that wind power is directly red into the grid.

Corresponding problems do not arise at thermal power plants since the primary energies gas, oil, coal and uranium are always available in the required quantities. Of course, the availability of hydro plants depends on precipitation which cannot be controlled by man just as the wind cannot be controlled. But the natural storage of water by earth and the use of storage reservoirs effect that hydro power is not that highly intermittent as is wind power. This is best recognized by the fact that hydro power production is usually not affected at all if it does not rain for some days. There will, however, be no wind power as soon as the wind speed is below cut-in.

As the utilities have not yet been confronted with highly stochastic energy sources like wind power, they did not develop a method how to calculate the available capacity of these energy sources. It is self-evident that any proposed method is the more likely to be accepted by the utilities the more the proposal follows the lines of the existing conventional methods. But as there is no single conventional method which is acceptable to all utilities, it can neither be expected that any proposed 'non conventional' method will be acceptable to all. This is neither claimed for the following proposal.

Emphasis is placed on the time problem. Time is disaggregated to time periods such that throughout every period the available capacity of the generation mix being considered is the same (in a statistical sense).

4.1. METHODOLOGY

4.1.1. THE LONG-TERM SYSTEM RELIABILITY CONCEPT

Be

- T any period in the future up to the time horizon of the generation expansion plan
- Z_T random variable "available capacity in the period T"
- L_T random variable or parameter "peak load in the period T"
- α maximum allowed loss of load probability (LOLP); $\alpha \in (0, 0.3)$

A safe power supply is said to be guaranteed in the period T if

$$\Pr(Z_t \leq L_T) < \alpha \tag{4.1}$$

where Pr: probability.

Of course, a safe power supply shall be guaranteed throughout T. Since it is not known at which time $t \in T$ the peak load will occur, this is not guaranteed by (4.1) without further ado. Sufficient conditions can be stated as follows: Be Z_t the random variable "available capacity at the time $t \in T$". A safe power supply is then guaranteed throughout T if

$$\Pr(Z_t \leq L_T) < \alpha \quad \text{for all } t \in T.$$

Thus, (4.1) guarantees a safe power supply throughout T if, for example, the distribution functions of Z_T and $Z_{t_1}, Z_{t_2}, \ldots$ are identical $(t_1, t_2, \ldots \in T)$:

$$\Pr(Z_T \leq z) = \Pr(Z_{t_1} \leq z) = \Pr(Z_{t_2} \leq z) = \ldots \tag{4.2}$$
$$\text{for all } z \in \mathbb{R}.$$

It will be shown in the following sections how T must be restricted such that (4.2) is fulfilled.

It must be emphasized that the actual utility calculations are not always that detailed. The more the time horizon of the generation expansion plan is approached, the longer the periods being considered are and the less (4.2) is fulfilled. Annual periods are not unusual. That such calculations are sufficiently precise, is shown by the empirical evidence that the power supply breaks down very rarely and if so it is mainly due to a breakdown of transmission lines but not due to the availability of power plants. There is no doubt that this must be attributed to the fact that the availability of thermal power plants highly depends on factors like the maintenance schedule which can be controlled by the utilities and which can be rescheduled if the plan does not coincide with the actual situation. A similar argument holds for hydro storage plants. The availability of wind power mainly depends on the wind speed which cannot be controlled. It is therefore reasonable to assume that the utilities will not accept such rough calculations with regard to the availability of wind power until the availability has been demonstrated.

4.1.2. Available Capacity of Thermal Units

Be

P_j nameplate capacity of the thermal unit j (fossil fueled unit or nuclear unit)

$q_{T,j}$ forced outage rate of the thermal unit j in the future period T

$q_{T,j} \equiv 1$ if the thermal unit j is scheduled for maintenance throughout the future period T

$X_{T,j}$ random variable "available capacity of the thermal unit j in the future period T"

The probability function of $X_{T,j}$ is given by

$$Pr(X_{T,j}=x_{T,j}) = \begin{cases} (1-q_{T,j}) & x_{T,j}=P_j \\ q_{T,j} & x_{T,j}=0 \\ 0 & \text{otherwise.} \end{cases} \qquad (4.3)$$

It follows from (4.3) that the random variable

$$X_T = \sum_{j=1}^{n} X_{T,j}$$

"available capacity of the thermal unit mix in the future period T"has the expected value

$$EX_T = \sum_{j=1}^{n} (1-q_{T,j})P_j. \tag{4.4}$$

As the random variables $X_{T,j}$ $(j=1,\ldots,n)$ can be assumed to be stochastically independent, the variance of X_T amounts to

$$\text{var } X_T = \sum_{j=1}^{n} q_{T,j}(1-q_{T,j})P_j^2. \tag{4.5}$$

The probability function of X_T can usually be approximated by a normal density with parameters EX_T and var X_T; see [1],[2].

We shall now investigate the problem how T must be restricted in order that (4.1) guarantees a safe power supply throughout T when Z_T is replaced by X_T.
The following conditions are sufficient:

a) No thermal unit will be dismantled during T.

b) The set of those units which are scheduled for maintenance remains constant over T.

c) The forced outage rates do not change within T.

As both the dismantlement and the maintenance schedule are planned by the utilities, they know in which periods a) and b) are fulfilled. The forced outrage rates mainly depend on the age of the units and can be assumed to be constant in periods up to at least a year. Hence, it is in principle not difficult to determine periods $T_1, T_2, \ldots$ such that (4.1) holds throughout $T_1, T_2, \ldots$. More periods will in general result compared with current standard. The current standard should be sufficient at small penetration rates of wind turbines. Large penetration rates will, however, require more thorough calculations.

4.1.3. Available Capacity of Hydro Plants

Let $a_1, a_2, \ldots$ be former periods which correspond to the future period T in the following sense: If, for example, T is the first week in January 1980, $a_1 (a_2, \ldots)$ must be the first week in any January in the past.

Now let h_{a_1}, $h_{a_2}, \ldots$ be the total hydro power production (MWh) in the period a_1, $a_2, \ldots$. Furthermore, let $k_{a_1} = k_{a_2} = \ldots$ be the number of hours in the period a_1, $a_2, \ldots$. A distribution function is then estimated from the megawatt sized data h_{a_1}/k_{a_1} , h_{a_2}/k_{a_2} ,... and the "available hydro capacity in the period T" is given by this distribution function. T usually covers a week or a month.

4.1.4. Available Capacity of Wind Turbines

Table 4.1 gives an impression of the problems which arise when determining the available capacity of wind turbines for a given time period.

mean hourly power output (MW)	December							average value
	1969	1970	1971	1972	1973	1974	1975	
0	22.2	34.0	24.2	21.8	30.2	21.3	18.7	24.6
(0.00-0.44)	20.4	25.9	13.3	13.6	19.5	19.0	10.1	17.4
[0.44-0.88)	9.3	6.6	3.0	8.6	6.0	7.0	4.0	6.4
[0.88-1.32)	10.8	9.3	8.1	12.4	7.5	14.9	7.0	10.0
[1.32-1.76)	6.3	7.5	8.2	7.3	6.5	8.9	8.9	7.7
[1.76-2.00)	4.6	2.7	2.4	8.2	2.3	2.7	1.6	3.5
2	26.5	14.0	40.9	28.2	28.0	26.2	49.7	30.5

Tab.4.1: Relative frequency distribution of the mean hourly WECS power output. Candidate site: Torslanda (Sweden). WECS type: Aeolus

It is seen from Tab. 4.1 that there are large annual differences. Thus, the following problem arises if the estimation of the distribution function of the random variable "available WECS capacity in December" is based on data from 1969 - 1975: the actually available WECS capacity will sometimes be considerably higher than the estimate and sometimes be considerably lower than the estimate. In the latter case, the power supply could be jeopardized at a large penetration rate of WECS. Therefore, a "worst case approach" is much more likely to be accepted by the utilities. Furthermore, there may be significant differences between the hourly WECS power outputs in the course of a day. For example, if there are significant daytime-nighttime differences and if the peak load occurs during daytime, the available WECS capacity should only be estimated from daytime data too (at least if the WECS power output during daytime is lower than during nighttime). In general, it is recommended to first determine those time periods where the WECS power output are significantly different. The following method can be used to determine these periods [4]:

Be

Y_{jkl} WECS power output in year j, month k (k=1,...,12), hour l (l=1,...,24).

The power output is modelled as

$$Y_{jkl} = \mu + \alpha_j + \beta_k + \gamma_l + \lambda_{jk} \pm \delta_{jl} + \omega_{kl} + \varepsilon_{jkl} + \text{error}$$

where

μ grand mean

α_j annual effect

β_k monthly effect

γ_l hourly effect

$\lambda, \delta, \omega, \varepsilon$ interaction effects.

The effects α, λ, δ and ε are assumed to be random effects. This is because the years are considered a sample out of the set of all years. The random effects are assumed to have a normal distribution with the expected value zero. A normal distribution with the expected value zero is also assumed for the "error".

The effects β, γ, δ as well as the variances of the random effects $\alpha, \lambda, \delta, \omega, \varepsilon$ and the variance of the "error" are estimated by the least-squares method. Based on these estimates, the following hypotheses are tested:

$$
\begin{array}{lll}
H_1: & \operatorname{var} \alpha = 0 & \text{(no annual effect)} \\
H_2: & \beta_1 = \dots = \beta_{12} = 0 & \text{(no monthly effect)} \\
H_3: & \gamma_1 = \dots = \gamma_{24} = 0 & \text{(no hourly effect)}
\end{array}
$$

$$
\left.
\begin{array}{ll}
H_4: & \operatorname{var} \lambda = 0 \\
H_5: & \operatorname{var} \delta = 0 \\
H_6: & \omega_{1,1} = \dots = \omega_{12,24} = 0 \\
H_7: & \operatorname{var} \varepsilon = 0
\end{array}
\right\} \text{(no interaction effects)}
$$

As for the test statistics, the reader is referred to [ ] or [ ].

If any of the a.m. hypotheses has to be rejected we do not know, which of the periods being considered differ in the WECS power output. The theory of linear contrasts can then be applied to answer such questions (see [3],[5]).

The presented method has been applied to hourly power output data of the German wind turbine Growian. An equal number of Growians was assumed to be installed at the Dutch coastal sites Cadzand, Kornwerderzand and Terschelling. Data period: January 1972 - December 1975. Instead of subdividing each year into 12 monthly periods, each year was subdivided into 13 4-week periods since this facilitates the calulations considerably. The results were as follows: the hypotheses H_1, H_2, H_3, H_4 and H_6 had to rejected at the significance level 0.05. The hypotheses H_5 and H_7 could be accepted at the same significance level.

The acceptance of H_5 means that the time-of-day dependence of the WECS power output does not depend on the actual year.

The non acceptance of H_1,H_2 and H_3 means that the WECS power output depends on the actual year, the actual month and the actual hour. Of course, this result was to expected due to causal explanations of the passage of wind speeds.

Due to the result that H_4 had to rejected, the available WECS capacity in month k (k=1,...,12(13)) should not be calculated by averaging over the WECS power outputs which occured in month k in different years. Further, due to the non acceptance of H_6, the available WECS capacity during the hour l (l=1,...,24) should not be calculated by averaging over the WECS power outputs which occured during the hour l in different months. Instead, the available WECS capacity during the hour l in month k should be calculated from the following data in order to be on the safe side:

Be j* the year with the lowest WECS power output in month k. The available WECS capacity during the hour l in month k is calculated from the WECS power outputs which occured during the hour l in month k and year j*. Of course, the WECS power outputs should account for forced outages and maintenance of wind turbines.

4.1.5. The Capacity Credit of Wind Turbines

Be

Z_T random variable "available capacity of the conventional generation mix in the period T"

Y_T random variable "available capacity of wind turbines in the period T"

L_T random variable or parameter "peak load in the period T"

c_T, d_T hypothetical firm capacities

α maximum allowed LOLP

The period T shall be such that (4.2) is fulfilled for both $X_T \equiv Z_T$ and $X_T \equiv Y_T$.

Note that firm capacities c_T, d_T, which do not exist in practice, are used to obtain operational definitions of the capacity credit.

Definition 1 (Effective Load Carrying Capability Concept)

The capacity credit of wind turbines in period T is given by the firm capacity c_T resulting from

$$Pr(Z_T < L_T) = Pr(Z_T - c_T + Y_T < L_T) < \alpha.$$

Comment

The planned conventional power plant mix guarantees a safe power supply as follows from $Pr(Z_T < L_T) < \alpha$. Adding wind turbines to the mix, the resulting mix will have a lower loss of load probability (LOLP) than the pure conventional mix, i.e. $Pr(Z_T < L_T) > Pr(Z_T + Y_T < L_T)$. Hence, one could dispense with conventional capacity when integrating wind turbines and the resulting mix would nevertheless guarantee a safe power supply.

Definition 2 (Equivalent Firm Capacity Concept)

The capacity credit of wind turbines in the period T is given by the firm capacity d_T resulting from

$$Pr(Z_T + d_T < L_T) = Pr(Z_T + Y_T < L_T) < \alpha.$$

<u>Comment</u>

This definition is useful if the planned conventional mix does not guarantee a safe power supply in the period T, i.e. $Pr(Z_T<L_T)>\alpha$. This offence against system reliability can be removed by additionally installing so many wind turbines that the available capacity Y_T of the wind turbines is such that $Pr(Z_T+Y_T<L_T)<\alpha$. Otherwise additional conventional capacity to the amount of d_T would have to be installed to restore system reliability. •

Let us now assume that the wind turbines can be put into operation from at least the beginning of the period T_1. If we then consider the periods $T_1, T_2, \ldots,$ the capacity credits of these different periods will in general be different too. As wind turbines can have one and only one capacity credit the question arises which capacity credit is the 'true' one.

We first have to determine how many periods have to be taken into account. This depends on the definition of the capacity credit.

We shall consider the periods $T_1, \ldots, T_n$ if Definition 1 is used whereby each period is such that

$$Pr(Z_{T_i}-c_{T_i}+Y_{T_i}<L_T) < \alpha \quad (i=1,\ldots,n).$$

The periods $T_1, \ldots, T_n$ cover the time span, conventional capacity can be replaced by the wind turbines without offending against system reliability.

We shall consider the periods $T_1, \ldots, T_m$ if Definition 2 is used. The periods cover the time span from the moment a given conventional generation mix fails to guarantee a safe power supply $(Pr(Z_{T_1}<L_{T_1})<\alpha)$ and system reliability is being restored by adding wind turbines $(Pr(Z_{T_1}+Y_{T_1}<L_{T_1})<\alpha)$ until the moment this generation mix fails to guarantee a safe power supply $(Pr(Z_{T_{m+1}}+Y_{T_{m+1}}<L_{T_{m+1}})>\alpha)$.

If Definition 1 is used, the capacity credit should be given by $c=\min\{c_1,...,c_n\}$. This guarantees that the generation mix composed of wind turbines and conventional units never has a greater LOLP that the pure conventional mix.

If Definition 2 is used, the capacity credit should be given by $d=\max\{d_1,...,d_m\}$. This guarantees that the pure conventional mix never has a greater LOLP than has the mix composed of conventional units and wind turbines.

The number of periods (n or m) may be that large that one has to restrict to some snapshot periods in practice.

The capacity credit as defined above indicates which conventional unit(s) may be displaced. As there do not exist firm capacities, the calculations should be repeated with the actual data of those unit(s) which may be displaced. The calculations should also take into account that the maintenance schedule may change if the generation mix includes wind turbines.

4.2 NUMERICAL RESULTS

The required data on the conventional generation system (generation expansion plan, forced outage rates, maintenance schedule, hydro power production) were provided by:

- the Tokyo Electric Power Company (TEPCO)
- N.V. tot Keuring van Elektrotechnische Materialien (KEMA)

- Statens Vattenfallswerke
- Solar Energy Research Institute (SERI)

The data are listed in the reports for the countries.

The capacity credit was calculated via the Effective Load Carrying Capability Concept (Japan, Sweden, USA) or via the Equivalent Firm Capacity Concept (the Netherlands). Except for Ludington, the month of the 1985 peak load is assumed to occur was chosen for the snapshot period. The annual peak load of the Ludington utility Consumers Power Company / Detroit Edison usually occurs in June. But since the WECS power output seemed to be significantly lower in July, July was more likely to yield the 'minimum' capacity credit and was therefore chosen for the snapshot period. Calculations of both the June and the July capacity credit showed that the assumption was correct; see p. 59 of the report for the United States.

The distribution function of the random variable Z_T was always approximated by a normal distribution. A normal distribution was also assumed for the random variable $Z_T + Y_T$. The parameters EY_T and $varY_T$ were in principle estimated from the WECS power output of the peak load month with the lowest WECS power output over the years. The time-of-day-dependence of the WECS power output was not taken into account. The WECS power output was higher during daytime (7 h - 19 h) in the peak load month at all candidate sites which entered the capacity credit calculations. Thus, estimating EY_T by the mean hourly WECS power output the expected value during daytime is underestimated. Furthermore, using all hourly WECS power outputs for the estimation of $varY_T$, the variance during daytime is overestimated. Since the peak load is assumed to occur during daytime, this method may be considered as a conservative approach to the capacity credit; the correct daytime estimates would result in a somewhat higher capacity credit.

Using the Effective Load Carrying Capability Concept, the capacity credit of n wind turbines is given by

$$c_T(n) = g(\beta_1) \cdot (\mathrm{var}Z_T + \mathrm{var}Y_T(n))^{1/2} + EZ_T + EY_T(n) - L_T$$

where

$g(\beta_1)$: β quantal of the standard normal distribution

β_1 : $\Pr\ (Z_T < L_T)$.

Using the Equivalent Firm Capacity Concept, the capacity credit of n wind turbines is given by

$$d_T(n) = - g(\beta_2) \cdot (\mathrm{var}Z_T)^{1/2} - EZ_T + L_T$$

where

β_2: $= \Pr\ (Z_T + Y_T(n) < L_T)$

Fig. 4.1 through Fig. 4.4 show the capacity credit in dependence on the number of WECS. It is seen that the capacity credit is decreasing if the number of WECS is increasing. This can be explained as follows: If the number of WECS is small, the variance of the random variable "available WECS capacity" (var Y_T) is very small compared with the variance of the conventional system (var Z_T). The capacity credit is then approximately given by the expected available WECS capacity, i.e. $c_T \approx EY_T$ and $d_T \approx EY_T$. If the number of WECS is increasing, var Y_T forms a larger amount of the total system variance (conventional units and WECS). Since EY_T increases less than var Y_T, the capacity credit per wind turbine decreases. Note that it is assumed that the siting of the wind turbines remains the same if the number of wind turbines increases.

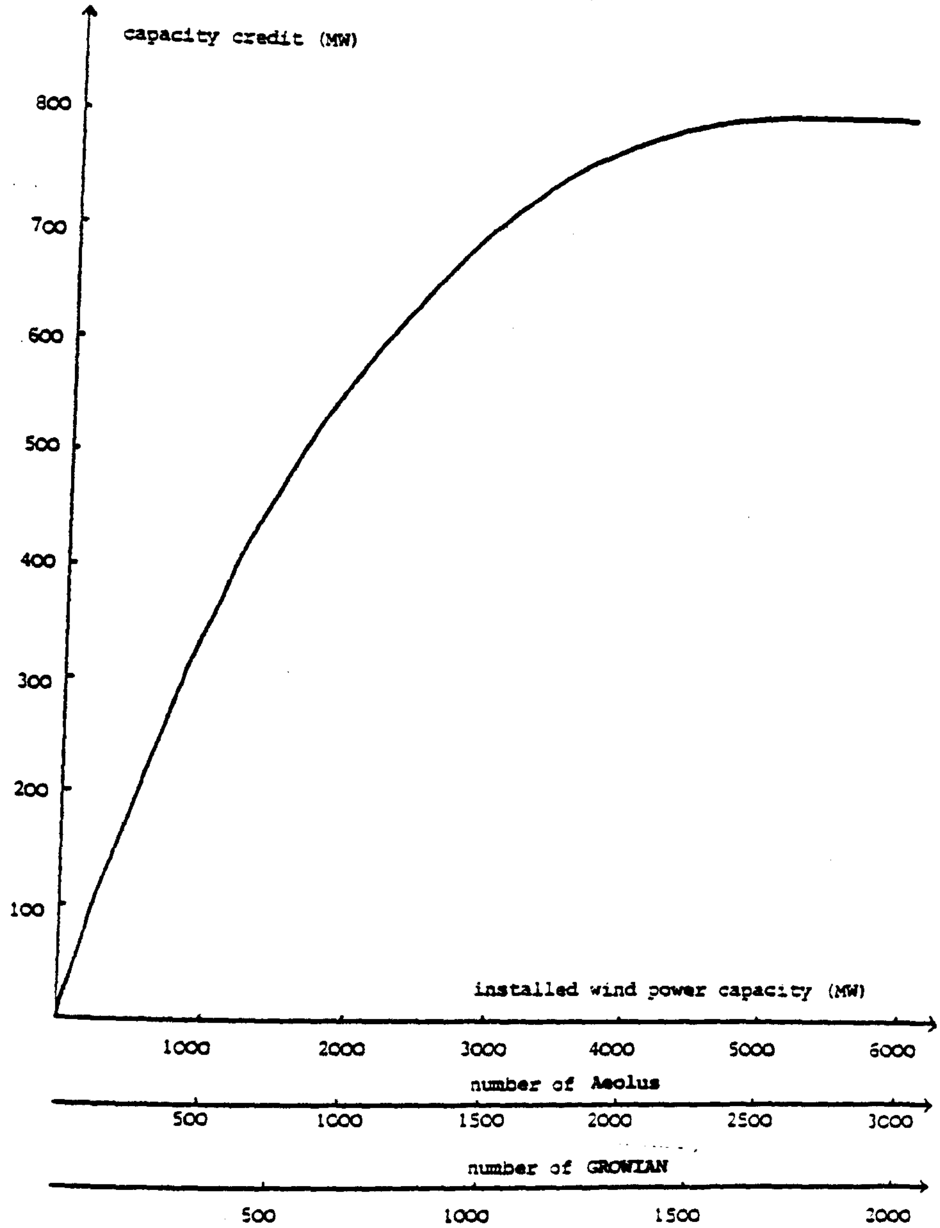
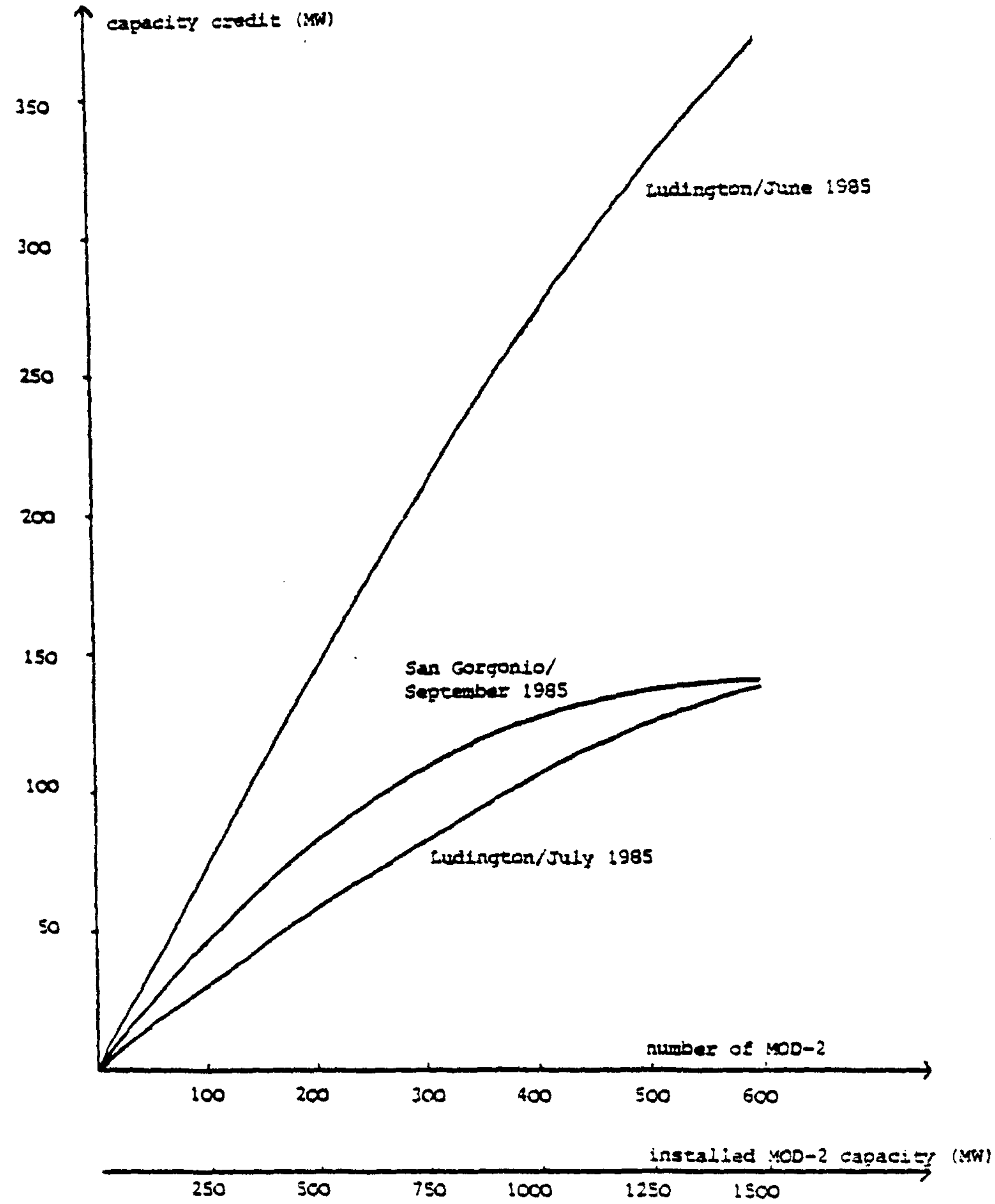


Fig.4.1: Capacity credit of wind turbines in December 1985 in the Swedish system



<u>Fig.4.2:</u> Capacity credit of MOD-2 wind turbines in the SCE system (San Gorgonio) and CPC/DE system (Ludington)

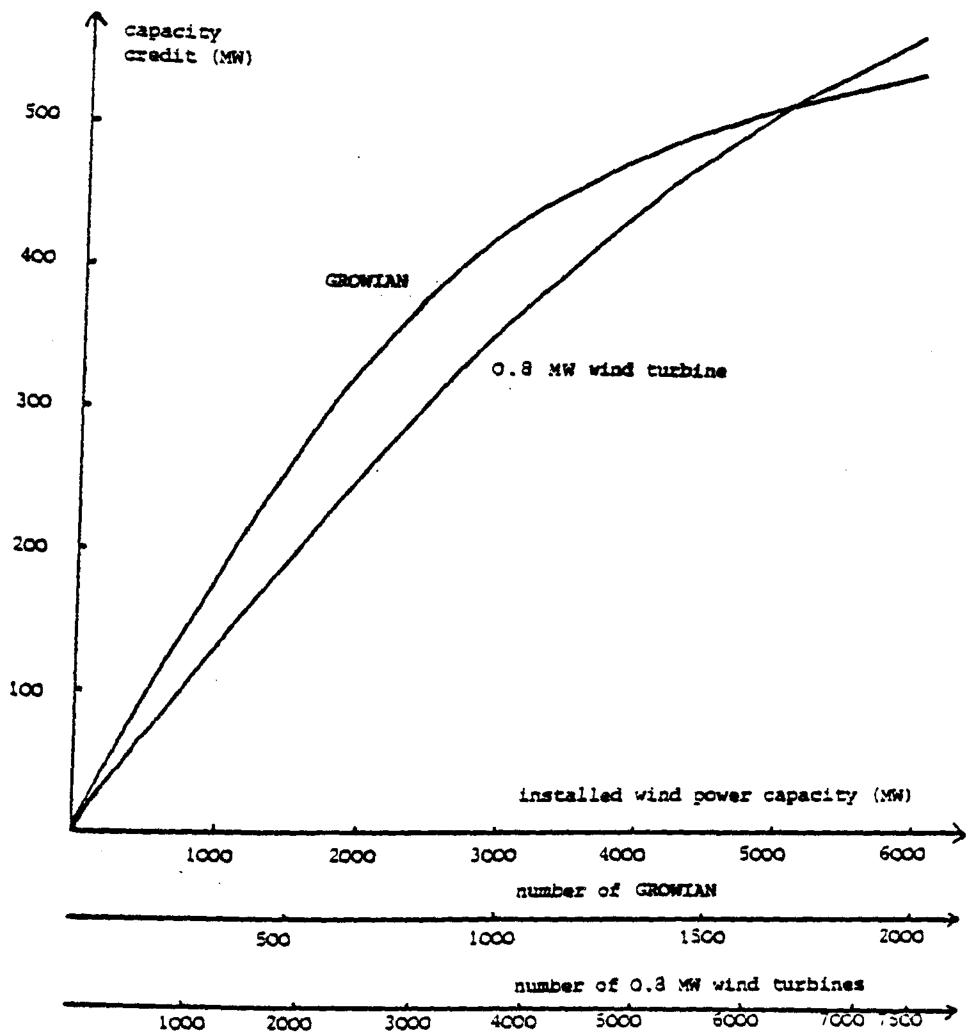


Fig.4.3: Capacity credits of wind turbines in the TEPCO system in July 1985

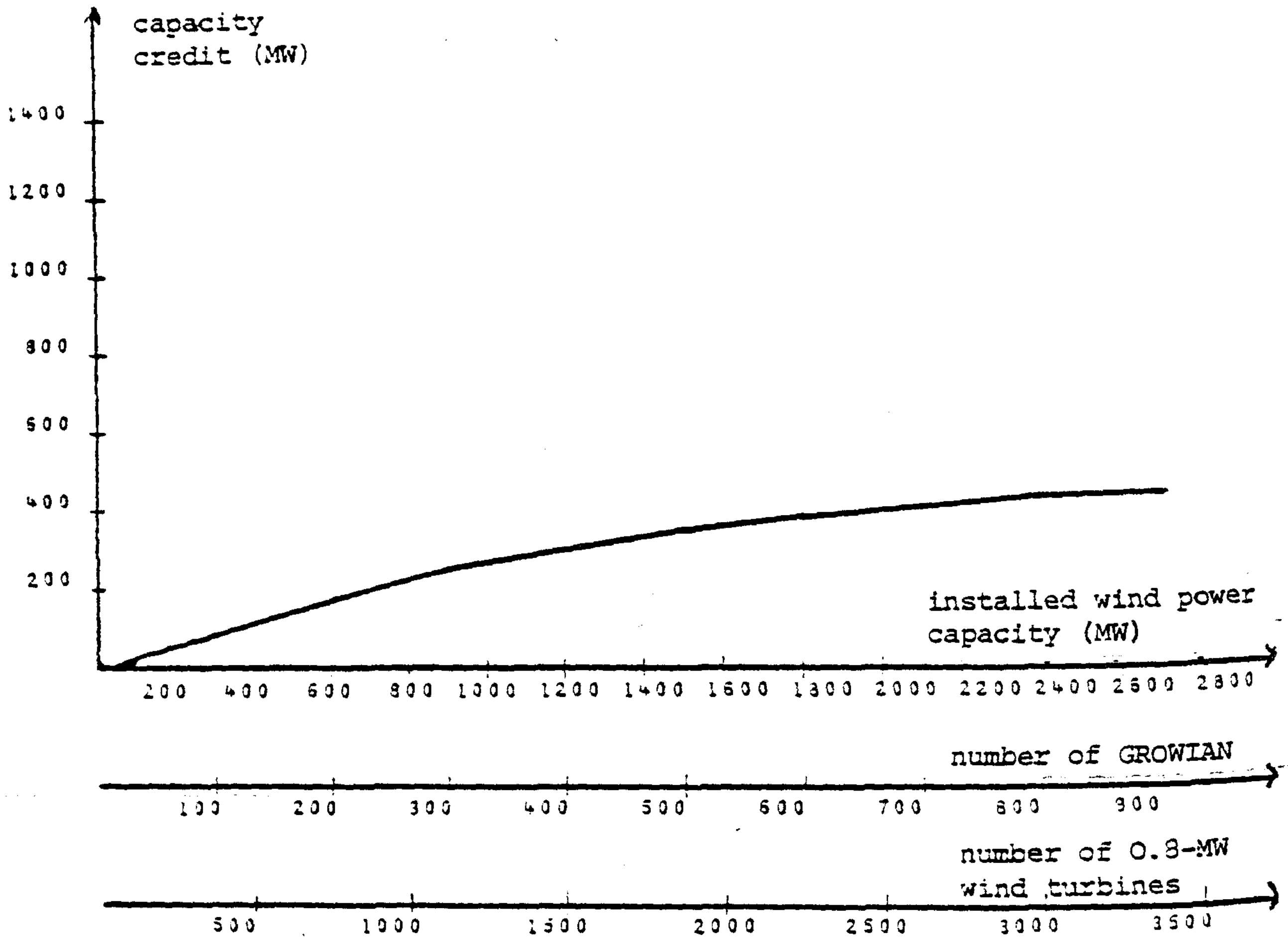


Fig.4.4: Capacity credit of wind turbines in the Dutch system in December 1985

4.3 References

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5 VALUE DETERMINATION OF WIND TURBINES

5.1 OVERVIEW

Electric utility systems are designed to operate at minimum cost with a prescribed level of reliability. In order to meet these goals, a generation expansion plan for capacity additions or replacements is devised to meet the load by minimizing the total cost, i.e., the capital, fuel, operating and maintenance costs.

The costs of non-experimental wind turbines are unknown so far. Cost estimates are based on vague assumptions regarding production costs and learning curves. Projected wind turbine costs have been addressed by numerous studies, i.e., [1], [9], [10]. One should bear in mind, that a grid connection (site-dependent cost, interfacing cost) of large-scale wind turbines will be quite complex and that large wind turbines do not have a well-developed manufacturing base so far. They are composed of different components with varying characteristics so that many different options are possible. According to this complexity in ranges of sizes, power and operating characteristics, it becomes extremely difficult to give reliable cost estimates. One study [6] even suggests that most cost data to date has failed to account for all the wind turbine installation, land, interconnections, transformers, protection equipment, project maintenance, O & M, etc. Furthermore, the costs of the experimental units are so far mainly determined by federally funded research, development and demonstration. Thus, the final costs being incurred at a stage of ultimate commercialization and mass production are uncertain.

Taking into account these uncertainties, a revenue requirement approach is pursued. The approach determines the breakeven cost of wind turbines. The breakeven value of a wind turbine is the maximum amount a utility can invest in a wind turbine with no cost or reliability disadvantages.

The value is realized by displacing high cost energy produced by fossil-fired units by lower cost energy produced by wind turbines (production savings), and by displacing or delaying conventional capacity by the wind turbine capacity (capital savings). That is, the approach pursued looks at the maximum savings caused by wind turbines in the utility system over some predefined planning horizon.

The value determination is based upon the assumption that no storage devices are dedicated to wind turbines. Dedicated storage is opposed to system storage which is not associated with any power plant and is operated much like other system generation. The assumption is made, as studies report that dedicated storage is not economically viable, regardless of the penetration. Though the dedicated storage increases the wind turbine value, the increase is not enough to overcome the estimated costs of the storage. Results of a storage analysis are, for example, given in [4], [8].

5.2 Production Savings

The production savings caused by wind are composed of the fuel savings, which result from displacing high cost fuels by wind, and of variable O & M savings, which are a result of the reduced energy output of the conventional units.

The wind turbine power output formed the input for the calculation of the production savings. As for Japan, the Netherlands, and Sweden 10 % were subtracted from the gross output, to account for forced outages of the wind turbines. The gross output of the two prime candidate sites in the United States was reduced by 8 %.

Tab. 5.1 gives the projected hourly load shares of 600 MOD-2 wind turbines at San Gorgonio in the SCE system up to the year 2000. The projections are subject to the assumption that in each hour of 1980, 1985, ... the same wind conditions hold as in the corresponding hour of 1979. The hourly load projections result from multiplying each hourly load of 1979 by the annual growth rate of electricity consumption. The annual growth rates were taken from utility planning studies.

A corresponding projection of the hourly load shares of 1.830 Aeolus wind turbines for the Swedish system is given in Tab. 5.2 1.830 Aeolus wind turbines are the maximum number of turbines being assessed for Sweden.

It can be concluded from Tab. 5.1 and Tab. 5.2 that the hourly load shares of the maximum number of turbines installed are smaller than 40 % (Sweden) and smaller than 30 % (SCE system) in 1990 and beyond. A projection of the daily load shares of 900 GROWIAN wind turbines integrated into the Dutch system confirms that the load shares remain under 40 %. The projection for the Netherlands is given in Tab. 5.3.

annual growth rate of electricity consumption		1,72%		1,72%/a		1,44%/a		1.44%/a		1,44%/a	
hourly load shares	1979		1980		1985		1990		1995		2000
0% - 10%	5496		5514		5662		5788		5918		6094
10% - 20%	2278		2311		2413		2521		2598		2603
20% - 30%	984		935		685		451		244		63
30% - 40%	2		0		0		0		0		0
40% - 50%	0		0		0		0		0		0
50% - 60%	0		0		0		0		0		0
60% - 70%	0		0		0		0		0		0
70% - 80%	0		0		0		0		0		0
80% - 90%	0		0		0		0		0		0
90% - 100%	0		0		0		0		0		0
100%	0		0		0		0		0		0

Tab. 5.1: Projection of the hourly load shares of 600 2.5 MW wind turbines at San Gorgonio

annual growth rate of elec. consumption		4%		3.5%		3.5%		2%		2%	

hourly load shares	1975	1980	1985	1990	1995	2000
0% - 10%	4287	4799	5349	5860	6198	6550
10% - 20%	2114	2222	2271	2264	2167	1985
20% - 30%	1344	1277	964	589	385	222
30% - 40%	708	377	169	46	10	3
40% - 50%	240	81	7	1	0	0
50% - 60%	63	4	0	0	0	0
60% - 70%	4	0	0	0	0	0
70% - 80%	0	0	0	0	0	0
80% - 90%	0	0	0	0	0	0
90% - 100%	0	0	0	0	0	0
100%	0	0	0	0	0	0

Tab.5.2: development of the hourly load shares of 1830 Aeolus wind turbines in Sweden

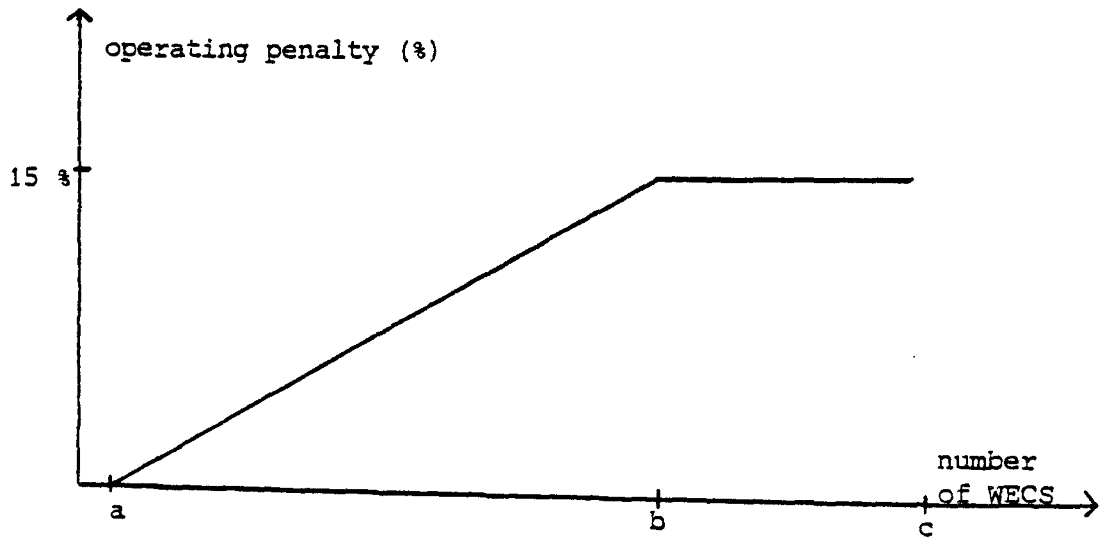
daily load share	y e a r 1975	1980	1985	1990	2000
> 1%	0.96	0.94	0.94	0.93	0.93
> 5%	0.82	0.80	0.78	0.75	0.70
> 10%	0.68	0.63	0.60	0.58	0.52
> 15%	0.57	0.51	0.84	0.44	0.36
> 20%	0.48	0.42	0.36	0.32	0.22
> 30%	0.34	0.21	0.15	0.09	0.01
> 40%	0.16	0.04	0.03	0.01	0.00
> 50%	0.04	0.01	0.00	0.00	0.00

Tab. 5.3: relative frequencies of the daily load shares of 900 GROWIAN wind turbines in the Netherlands. Annual growth rates of load: 4 % from 1975 - 1980; 2 % from 1980 onwards.

In this report the production savings of up to 1.000 wind turbines are determined. Taking into account the modest load shares of the wind turbines in future years, shown in Tab. 5.1 through Tab. 5.3, it was assumed that the total adjusted wind turbine output is fed into the grid (no excess-assumption).

That is, it is deduced that there are no situations neither during daytime nor during nighttime where wind energy may have to be dumped to avoid shutting down a large base load unit. To date it holds true that especially during nighttime, the load is met by base load units only. The no excess-assumption in such a case assumes that either the base load units adapt their generation to a load decline or the collection of units to serve the load during these particular hours can be rearranged.

The gross wind turbine output adjusted for forced outages was then again decreased because of the intermittent nature of wind. Because the wind is available intermittently, the utility has minimum control over the level of wind generation at any time. To secure operation, the regulating capacity and the load following capability of a wind-assisted system has to be enlarged to project against any wind power shortfalls. The changes in unit commitment and dispatch have been outlined in Chapter 3. The costs which are incurred by these changes are imposed as operating penalty on the wind turbines. The operating penalty consists in subtracting up to 15 % from the wind power output adjusted for forced outages. The operating penalty is sketched below.



a: number of WECS such that the sum of the WECS nameplate capacities amounts to 1 % of the expected minimum load in 1985

b: number of WECS such that the penetration rate of WECS (sum of WECS nameplate capacities / total installed thermal capacity in 1985) amounts to about 10 %

c: maximum number of WECS

The penalty has been inferred from the literature on the impacts of wind turbines on system operation, see e.g. [5], [10], [12], [13].

The production savings per wind turbine if n wind turbines are installed, were calculated for the countries Japan, the Netherlands, and Sweden as follows:

$$S(n) = \underbrace{x(n) \cdot p^{fuel} \cdot \sigma}_{\text{fuel savings}} + \underbrace{x(n) \cdot p_{var}^{O\&M} \cdot \gamma}_{\text{var.O\&M savings}}$$

where

$x(n)$ annual power output per wind turbine (gross output minus 10 % for forced outages minus the operating penalty)

p^{fuel} average costs of the displaced fuels in 1985

$p_{var}^{O\&M}$ variable O&M costs of conventional units in 1985

$\sigma(\gamma)$ present value factor of fuel savings (variable O & M savings)

$$\sigma = \sum_{k=0}^{t-1} \left(\frac{1+\hat{p}^{fuel}}{1+r}\right)^k \qquad 1+\hat{p}^{fuel} \neq 1+r$$

$$\gamma = \sum_{k=0}^{t-1} \left(\frac{1+\hat{p}_{var}^{O\&M}}{1+r}\right)^k \qquad 1+\hat{p}_{var}^{O\&M} \neq 1+r$$

t	wind turbine lifetime
$\hat{p}^{fuel}$	annual escalation rate of fuel costs from 1985 onwards (including inflation)
$\hat{p}^{O\&M}_{var}$	annual escalation rate of variable O&M costs from 1985 onwards (including inflation)
r	constant discount rate (including inflation)

As for the United States, the evaluation was modified to take into account the financial setup of the utility, and the tax status of ownership of the wind turbines.

$$S'(n) = \frac{1}{FCR} \cdot [x(n) \cdot p^{fuel} \cdot \sigma + x(n) \cdot p^{O\&M}_{var} \cdot \gamma] \cdot CRF$$

where

FCR	fixed charge rate for wind turbines
CRF	capital recovery factor

$$CRF = \frac{r(1+r)^t}{(1+r)^t - 1} \qquad r \neq 0$$

It is obvious from the production value equation that differences in the assumptions of the various economic parameters can grossly affect the calculated value. Sensitivity calculations were made with regard to the operating lifetime of the turbine (20 yrs; 30 yrs), the fuel cost escalation assumption (two escalation rates from 1985 onwards), and the annual wind turbine output.

The fuel cost data were provided by the Participants and represent end-of-year (EOY) 1980 values. These are equivalent to beginning-of-year (BOY) 1981 values. The (EOY) fuel cost data are tabulated in Tab. 5.4.

fuel	Japan	the Netherlands	Sweden	USA
oil	0.071	0.058	0.052	0.064
gas	0.062	0.058	-	-
coal	-	0.028	0.025	0.013

Tab. 5.4: EOY 1980 fuel cost in $/kwh.
1 US $ = 226.77 Yen = 2.5 hfl = 5.56 skr

To make a 20-year (30-year) present value calculation for a wind turbine beginning operation in January 1985, the (EOY) 1980 fuel cost data were escalated up to 1985. The escalation assumptions for the period 1980 - 1985 are given in Tab. 5.5.

	Japan	the Netherlands	Sweden	USA
constant inflation rate i	5 %	7 %	8 %	10 %
annual fuel cost escalation rate (excluding inflation)	3 %	1 %	0 %	1.4 % coal 1.8 % oil

Tab.5.5: Inflation rate and fuel cost escalation rate (period: 1980 - 1985)

The (BOY) 1985 fuel cost estimates are shown in Tab. 5.6.

fuel	Japan	the Netherlands	Sweden	USA
oil	0.096	0.079	0.071	0.1
gas	0.084	0.079	-	-
coal	-	0.038	0.034	0.02

Tab.5.6: Estimated BOY 1985 fuel cost in $/kWh
1 US $ = 226.77 Yen = 2.5 hfl = 5.56 skr

The general economic input parameter assumptions over the period 1985 - 2005 or 1985 - 2015 are shown in Tab. 5.7.

	Japan	the Netherlands	Sweden	USA
constant discount rate (incl. inflation) r	9 %	11 %	12 %	12 %
constant inflation rate i	5 %	7 %	8 %	8 %
annual fuel cost escalation rate (excl. inflation	lowest: 0% highest: 3%	lowest: 1% highest: 3%	lowest: 0% highest: 4%	lowest: 1% highest: 2%

Tab.5.7: General economic input parameter assumptions (period: 1985 - 2005 / 1985 - 2015)

The utility specific economic parameters used in the calculations of the production savings are compiled below.

	Japan	the Netherlands	Sweden	U S A San Gorgorio	Ludington
ratio of displaced fuels	oil : gas = 5 : 5	oil/gas : coal = 7 : 3	oil : coal = 8 : 2	oil : coal = 9 : 1	oil : coal = 4 : 6
p^{fuel} (1985 $/kWh)	0.090	0.0667	0.0636	0.092	0.052
$p^{O\&M}$ (1985 $/kWh)	0.0044	0.0040	0.0036	0.0035	0.0035
$\beta^{O\&M}$	5 %	7 %	8 %	8 %	8 %
lowest/highest annual WECS power output (GWh per year)	GROWIAN: 9/11 0.8 MW: 1.5/2.5	GROWIAN: 9/12 0.8 MW: 2/3	GROWIAN: 9/11 Aeolus: 5/7	MOD-2: 8.09	MOD-2: 7.82
lowest/highest escalation rate of fuel prices β^{fuel}	5%/8%	8%/10%	8%/12%	9%/10%	9%/10%
fixed charge rate for wind turbines				lifetime 20 years:0.18 lifetime 30 years:0.19	

In the following tables, the 'best' case is the one with the highest annual WECS power output and the highest escalation rate of fuel prices. Correspondingly, the 'worst' case is the one with the lowest annual WECS power output and the lowest escalation rate of fuel prices.

For all the countries, the production savings decrease with increasing wind penetration. The decrease is due to the need for additional regulating capacity and a more flexible commitment including a shift to more energy-consuming conventional units to compensate for the wind power variations. The two factors are comprised in the operating penalty introduced above.

The calculations indicate that the fuel savings are by far the biggest element of the production savings. The variable O & M savings were always less than 6 %.

The evaluations indicate that the value of the production savings is most sensitive to the lifetime of the wind turbines. Given a lifetime, the value of the fuel savings is highly sensitive to the fuel costs and the estimated escalation rate of the fuel costs.

For a complete derivation of the results, and an extensive discussion of the results, the reader is referred to the reports for the Participants in the Task.

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operating lifetime 20 yrs		number of wind turbines 50	100	500	1000
percent penetration[a] in 1985		0.41	0.82	4.1	8.2
GROWIAN	'worst'	3657	3657	3535	3230
	'best'	5658	5658	5469	4997
percent penetration in 1985		0.11	0.22	1.1	2.2
0.8 MW	'worst'	2285	2285	2285	2285
	'best'	4822	4822	4822	4822

<u>Tab.5.8:</u> Bandwidth of production savings per wind turbine (in 1985 $/kW); peak demand of TEPCO

[a] penetration is the rated capacity of the wind turbines, expressed as a percentage of peak demand

operating lifetime 30 yrs	number of wind turbines 50	100	500	1000
percent penetration in 1985	0.41	0.82	4.1	8.2
GROWIAN 'worst'	4683	4683	4527	4137
GROWIAN 'best'	8087	8087	7817	7144
percent penetration in 1985	0.11	0.22	1.1	2.2
0.8 MW 'worst'	2927	2927	2927	2927
0.8 MW 'best'	6892	6892	6892	6892

Tab.5.9: Bandwidth of production savings per wind turbine (in 1985 $/kW)

T h e N e t h e r l a n d s

operating lifetime 20 yrs	number of wind turbines 50	100	500	1000
GROWIAN 'worst'	2959	2919	2601	2522
GROWIAN 'best'	3456	3410	3038	2946
percent penetration in 1985	1.3	2.6	1.3	2.6
0.8 MW 'worst'	2478	2472	2411	2322
0.8 MW 'best'	2888	2888	2817	2713

Tab.5.10: Bandwidth of production savings per wind turbine (in 1985 $/kW); peak demand of the Netherlands in total

operating lifetime 30 yrs		number of wind turbines 50	100	500	1000
percent penetration in 1985		1.3	2.6	1.3	2.6
GROWIAN	'worst'	3924	3871	3450	3344
	'best'	4940	4873	4343	4210
percent penetration in 1985		0.34	0.7	3.5	7.0
0.8 MW	'worst'	3279	3279	3197	3080
	'best'	4127	4127	4024	3877

Tab.5.11: Bandwidth of production savings per wind turbine (in 1985 \$/kW)

S w e d e n

operating lifetime 20 yrs		number of wind turbines 50	100	500	1000
percent penetration in 1985		0.49	0.98	4.9	9.8
Aeolus	'worst'	2182	2153	1918	1860
	'best'	4160	4104	3657	3545
percent penetration in 1985		0.735	1.47	7.35	14.7
GROWIAN	'worst'	2619	2583	2302	2232
	'best'	4358	4299	3831	3714

Tab.5.12: Bandwidth of production savings per wind turbine (in 1985 \$/kW); peak demand of Sweden in total

operating lifetime 30 yrs	number of wind turbines 50	100	500	1000
percent penetration in 1985	0.49	0.98	4.9	9.8
Aeolus 'worst'	2804	2766	2465	2390
Aeolus 'best'	6204	6121	5455	5288
percent penetration in 1985	0.74	1.47	7.35	14.7
GROWIAN 'worst'	3365	3320	2958	2868
GROWIAN 'best'	6500	6413	5714	5540

Tab.5.13: Bandwidth of production savings per wind turbine (in 1985 \$/kW)

U S A

operating lifetime 20 yrs	number of wind turbines 50	100	500	1000
San Gorgonio, CA percent penetration[a)] in 1985	0.85	1.7	8.5	1.7
MOD-2 'worst'	3006	2906	2646	2575
MOD-2 'best'	3255	3211	2866	2789
Ludington, MI percent penetration[b)] in 1985	0.88	1.76	8.8	17.6
MOD-2 'worst'	1649	1631	1490	1410
MOD-2 'best'	1785	1766	1613	1527

Tab.5.14: Production savings per wind turbine (in 1985 \$/kW); [a)] peak demand of SCE system; [b)] peak demand of CPC/DE system

operating lifetime 30 yrs	number of wind turbines 50	100	500	1000
San Gorgonio, CA percent penetration in 1985	0.85	1.7	8.5	1.7
MOD-2 'worst'	3911	3859	3445	3351
MOD-2 'best'	4395	4337	3871	3766
Ludington, MI percent penetration in 1985	0.88	1.76	8.8	17.6
MOD-2 'worst'	2146	2123	1939	1837
MOD-2 'best'	2411	2385	2179	2060

Tab.5.15: Production savings per wind turbine (in 1985 \$/kW)

5.3 Capital Savings

The conventional capacity (MW), which can be displaced by wind turbines without degrading system reliability, is defined as capacity credit of the wind turbines. The determination of the megawatt-sized capacity credit is discussed in Chapter 4. Converted in monetary savings by multiplying with the capital costs of the displaced unit(s) and adding together with corresponding savings of fixed O & M cost, the capital savings result.

Fixed O & M cost, which can be saved, cover staffing and manpower cost, cost of repairs, replacement of parts, rents, taxes and insurances, and all the other items which are independent of the operation time of the system.

The capital savings per wind turbine if n wind turbines are installed, were calculated for the countries Japan, the Netherlands and Sweden as follows:

$$C(n) = c(n) \cdot \frac{1}{n} \cdot [p^{cap} + p_{fix}^{O\&M} \cdot \varepsilon]$$

where

$c(n)$	megawatt-sized capacity credit of n wind turbines
n	number of wind turbines
p^{cap}	unit capital cost
$p_{fix}^{O\&M}$	fixed O & M cost
ε	present value factor of fixed O & M savings

$$\varepsilon = \sum_{k=0}^{t-1} \left(\frac{1+\hat{p}_{fix}^{O\&M}}{1+r}\right)^k \qquad 1+\hat{p}_{fix}^{O\&M} \neq 1+r$$

t	wind turbine lifetime
$\hat{p}_{fix}^{O\&M}$	annual escalation rate of fixed O & M costs from 1985 onwards (including inflation)
r	constant discount rate (including inflation)

To reflect the variations in types of financing and tax structures, the capital savings for the electric utility systems in the United States are calculated as

$$C'(n) = c(n) \cdot \frac{1}{n \cdot FCR} \cdot [p^{cap} \cdot FCR_{displ.} + p_{fix}^{O\&M} \cdot \varepsilon \cdot CRF]$$

where

$FCR_{displ.}$	fixed charge rate for plant type displaced
FCR	fixed charge rate for wind turbines
CRF	capital recovery factor

Once a capital expenditure is made, the cost of the capital expenditure will not change. As a result, the capital investment expressed by the first term on the right hand side of the equations will not change.

Thus, the capital investment expressed by the first term is not subject to inflation and escalation. These items are considered by the appropriate present value factor ε of the fixed O & M cost instead.

Typical cost estimates which were used in the reports are listed in Tab. 5.16.

	Japan	the Netherlands	Sweden	USA
p^{cap} in 1985 \$/kW	792	800	900	650
$p^{O\&M}_{fix}$ in 1985 \$/kW	66	48	54	3
$\hat{p}^{O\&M}_{fix}$	5 %	7 %	8 %	8 %
r	9 %	11 %	12 %	12 %
wind turbine life-time in years	20/30	20/30	20/30	20/30

Tab.5.16: Economic input parameters to the calculation of the capital savings.
1 US \$ = 226,77 Yen = 2.5 hfl = 5.56 skr

The capital savings which are listed in Tab. 5.17 through Tab. 5.24 have been calculated with the parameters of Tab. 5.16.

It is seen that the capital savings decrease if the number of wind turbines increases. The reasons have already been mentioned in Chapter 4.

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operating lifetime 20 yrs	number of wind turbines 50	100	500	1000
GROWIAN	361	355	310	253
penetration[a] in 1985	0.41	0.82	4.1	8.2
0.8 MW	267	263	255	249
penetration in 1985	0.11	0.22	1.1	2.2

Tab.5.17: Capital savings per wind turbine (in 1985 $/kW);
a) penetration is the rated capacity of the wind turbines, expressed as a percentage of peak demand of TEPCO

operating lifetime 30 yrs	number of wind turbines 50	100	500	1000
GROWIAN	417	409	357	295
penetration in 1985	0.41	0.82	4.1	8.2
0.8 MW	308	303	294	286
penetration in 1985	0.11	0.22	1.1	2.2

Tab.5.18: Capital savings per wind turbine (in 1985 $/kW)

t h e N e t h e r l a n d s

operating lifetime 20 yrs	number of wind turbines 50	100	500	1000
GROWIAN	483	472	349	216
penetration[a] in 1985	1.3	2.6	1.3	2.6
0.8 MW	494	494	461	422
penetration in in 1985	0.35	0.7	3.5	7.0

Tab.5.19: Capital savings per wind turbine (in 1985 $/kW)

a) penetration is the rated capacity of the wind turbines, expressed as a percentage of peak demand of the Netherlands

operating lifetime 30 yrs	numbers of wind turbines 50	100	500	1000
GROWIAN	547	535	394	244
penetration in 1985	1.3	2.6	1.3	2.6
0.8 MW	559	559	522	477
penetration in 1985	0.35	0.7	3.5	7.0

Tab.5.20: Capital savings per wind turbine (in 1985 $/kW)

S w e d e n

operating lifetime 20 yrs	numbers of wind turbines 50	100	500	1000
Aeolus	676	659	571	477
penetration[a] in 1985	0.49	0.98	4.9	9.8
GROWIAN	666	646	523	395
penetration in 1985	0.735	1.47	7.35	14.7

Tab.5.21: Capital savings per wind turbine (in 1985 $/kW)

a) penetration is the rated capacity of the wind turbines, expressed as a percentage of peak demand of Sweden in total

operating lifetime 30 yrs	number of wind turbines 50	100	500	1000
Aeolus	765	746	647	540
penetration	0.49	0.98	4.9	9.8
GROWIAN	754	731	592	448
penetration	0.74	1.47	7.35	14.7

Tab.5.22: Capital savings per wind turbine (in 1985 $/kW)

U S A

operating lifetime 20 yrs	number of wind turbines 50	100	500	1000
San Gorgonio MOD-2	131	124	73	22
penetration[a] in 1985	0.85	1.7	8.5	1.7
Ludington MOD-2	83	82	66	46
penetration[b] in 1985	0.88	1.76	8.8	17.6

Tab.5.23: Capital savings per wind turbine (in 1985 $/kW)

a) penetration is the rated capacity of the wind turbines, expressed as a percentage of peak demand of the SCE system

b) CPC/DE system

operating lifetime 30 yrs	number of wind turbines 50	100	500	1000
San Gorgonio MOD-2	133	125	74	22
penetration in 1985	0.85	1.7	8.5	1.7
Ludington MOD-2	84	83	67	47
penetration in 1985	0.88	1.76	8.8	17.6

Tab.5.24: Capital savings per wind turbine (in 1985 $/kW)

5.4 BREAKEVEN VALUE PER WIND TURBINE

The breakeven value per wind turbine is estimated in terms of the savings realized both in the electric utility all-day production and the expansion planning for conventional units.

The breakeven value results from adding together the production savings and the capital savings.

$$V(n) = S(n) + C(n)$$

where

V(n) breakeven value per wind turbine if n wind turbines are installed

By definition, the breakeven value is the maximum amount that could be spent on a wind turbine by the utility without any disadvantage in cost and reliability. The breakeven value has to comprise all the expenses incurred over the wind turbine lifetime, such as fabrication, installation, checkout, interfacing, operation, maintenance, land lease, insurance, and decommissioning. That is, both the manufacturers and owners costs have to be covered.

The breakeven value per wind turbine for the 1985 scenario of the participating countries is given in Tab. 5.24 through Tab. 5.39. For convenience, the production savings and the capital savings are presented in addition. Different wind turbine penetration levels are considered. The penetration is the rated capacity of the wind turbines, expressed as a percentage of the peak demand of each system.

The results indicate that the breakeven value is mainly determined by the production savings. Capital savings made up only roughly

Japan:	4 % - 9 %	GROWIAN
	4 % - 10.5 %	0.8 MW wind turbine
the Netherlands:	5.5 % - 14 %	GROWIAN
	10.9 % - 16.7 %	0.8 MW wind turbine
Sweden:	7.5 % - 20.3 %	GROWIAN
	9.3 % - 23.7 %	Aeolus
USA:	0.6 % - 4.8 %	MOD-2

of the total value. The bandwidth is primarily determined by the number of turbines installed. The lower (upper) limit corresponds to 1000 (50) wind turbines.

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GROWIAN lifetime: 20 yrs	number of wind turbines 50	100	500	1000
penetration in 1985	0.41	0.82	4.1	8.2
production sav.	3657-5658	3657-5658	3535-5409	3230-4997
capital savings	361	355	310	253
value	4018-6019	4012-6013	3845-5779	3483-5250

Tab.5.24: Estimated breakeven value of GROWIAN for the TEPCO system (in 1985 $ per kW)

GROWIAN lifetime: 30 yrs	number of wind turbines 50	100	500	1000
penetration in 1985	0.41	0.82	4.1	8.2
production sav.	4683-8087	4683-8087	4527-7817	4137-7144
capital savings	417	409	357	295
value	5100-8504	5092-8496	4884-8174	4432-7439

Tab.5.25: Estimated breakeven value of GROWIAN for the TEPCO system (in 1985 $ per kW)

0.8 MW lifetime: 20 yrs	number of wind turbines 50	 100	 500	 1000
penetration in 1985	0.11	0.22	1.1	2.2
production sav.	2285-4822	2285-4822	2285-4822	2285-4822
capital savings	267	263	255	249
value	2552-5089	2548-5085	2540-5077	2534-5071

Tab.5.26: Estimated breakeven value of the 0.8 MW wind turbine for the TEPCO system (in 1985 $ per kW)

0.8 MW lifetime: 30 yrs	number of wind turbines 50	 100	 500	 1000
penetration in 1985	0.11	0.22	1.1	2.2
production sav.	2927-6892	2927-6892	2927-2892	2927-6892
capital savings	308	303	294	286
value	3235-7200	3230-7195	3221-7186	3213-7178

Tab.5.27: Estimated breakeven value of the 0.8 MW wind turbine for the TEPCO system (in 1985 $ per kW)

t h e   N e t h e r l a n d s

GROWIAN lifetime: 20 yrs	number of wind turbines 50	100	500	1000
penetration in 1985	1.3	2.6	13	26
production sav.	2959-3456	2919-3410	2601-3038	2522-2946
capital savings	483	472	349	216
value	3442-3939	3391-3882	2950-3387	2738-3162

Tab.5.28: Estimated breakeven value of GROWIAN for the Dutch system (in 1985 $ per kW)

GROWIAN lifetime: 30 yrs	number of wind turbines 50	100	500	1000
penetration in 1985	1.3	2.6	13	26
production sav.	3924-4940	3871-4873	3450-4343	3344-4210
capital savings	547	535	394	244
value	4471-5487	4406-5408	3844-4737	3588-4454

Tab.5.29: Estimated breakeven value of GROWIAN for the Dutch system (in 1985 $ per kW)

0.8 MW lifetime: 20 yrs	number of wind turbines 50	 100	 500	 1000
penetration in 1985	0.35	0.7	3.5	7
production sav.	2472-2888	2472-2888	2411-2817	2322-2713
capital savings	494	494	461	422
value	2966-3382	2966-3382	2872-3278	2744-3135

Tab.5.30: Estimated breakeven value of the 0.8 MW wind turbine in the Dutch system (in 1985 $ per kW)

0.8 MW lifetime: 30 yrs	number of wind turbines 50	 100	 500	 1000
penetration in 1985	0.35	0.7	3.5	7
production sav.	3279-4127	3279-4127	3197-4024	3080-3877
capital savings	559	559	522	477
value	3838-4686	3838-4686	3719-4546	3557-4354

Tab.5.31: Estimated breakeven value of the 0.8 MW wind turbine in the Dutch system (in 1985 $ per kW)

Sweden

GROWIAN lifetime: 20 yrs	number of wind turbines 50	100	500	1000
penetration in 1985	0.735	1.47	7.35	14.7
production sav.	2619-4358	2583-4299	2302-3831	2232-3714
capital savings	666	646	523	395
value	3285-5024	3229-4945	2825-4354	2627-4109

Tab.5.32: Estimated breakeven value of GROWIAN in the Swedish system (in 1985 $ per kW)

GROWIAN lifetime: 30 yrs	number of wind turbines 50	100	500	1000
penetration in 1985	0.735	1.47	7.35	14.7
production sav.	3365-6500	3320-6413	2958-5714	2868-5540
capital savings	754	731	592	448
value	4119-7254	4051-7144	3550-6306	3316-5988

Tab.5.33: Estimated breakeven value of GROWIAN in the Swedish system (in 1985 $ per kW)

Aeolus lifetime: 20 yrs	number of wind turbines 50	100	500	1000
penetration in 1985	0.49	0.98	4.9	9.8
production sav.	2182-4160	2153-4104	1918-3657	1860-3545
capital savings	676	659	571	477
value	2858-4836	2812-4763	2489-4228	2337-4022

Tab.5.34: Estimated breakeven value of Aeoulus in the Swedish system (in 1985 $ per kW)

Aeolus lifetime: 30 yrs	50	100	500	1000
penetration in 1985	0.49	0.98	4.9	9.8
production sav.	2804-6204	2766-6121	2465-5455	2390-5288
capital savings	765	746	647	540
value	3569-6969	3512-6867	3112-6102	2930-5828

Tab.5.35: Estimated breakeven value of Aeolus in the Swedish system (in 1985 $ per kW)

U S A

MOD-2 lifetime: 20 yrs	number of wind turbines 50	 100	 500	 1000
San Gorgonio penetration in 1985	0.85	1.7	8.5	17
production sav.	3006-3255	2906-3211	2646-2866	2575-2789
capital savings	131	124	73	22
value	3137-3386	3030-3335	2719-2939	2597-2811

Tab.5.36: Estimated breakeven value of MOD-2 in the SCE system (in 1985 \$ per kW)

MOD-2 lifetime: 20 yrs	number of wind turbines 50	 100	 500	 1000
Ludington penetration in 1985	0.88	1.76	8.8	17.6
production sav.	1649-1785	1631-1766	1490-1613	1410-1527
capital savings	83	82	66	46
value	1732-1868	1713-1848	1556-1679	1456-1573

Tab.5.37: Estimated breakeven value of MOD-2 in the CPC/DE system (in 1985 \$ per kW)

MOD-2 lifetime: 30 yrs	number of wind turbines 50	 100	 500	 1000
San Gorgonio penetration in 1985	0.85	1.7	8.5	17
production sav.	3911-4395	3859-4337	3445-3871	3351-3766
capital savings	133	125	74	22
value	4044-4528	3984-4462	3519-3945	3373-3788

Tab.5.38: Estimated breakeven value of MOD-2 in the SCE system (in 1985 \$ per kW)

MOD-2 lifetime: 30 yrs	number of wind turbines 50	 100	 500	 1000
Ludington penetration in 1985	0.88	1.76	8.8	17.6
production sav.	2146-2411	2123-2385	1939-2179	1837-2060
capital savings	84	83	67	47
value	2230-2495	2206-2468	2006-2246	1884-2107

Tab.5.39: Estimated breakeven value of MOD-2 in the CPC/DE system (in 1985 \$ per kW)

5.5 BREAKEVEN VALUE AND COSTINGS FOR WIND TURBINES

The preceding section shows calculated values of wind turbines for a single site and a utility combination (USA) and for a dispersed siting and a utility combination (Japan, the Netherlands, Sweden). For each combination the breakeven value of two wind turbine systems for a number of penetrations has been calculated.

The next step prior to any investment would be to compare these breakeven values with projected wind turbine costs.

To date, even a small number of wind turbines on a commercial basis does not exist. The current lack of fully demonstrated wind turbine performance and O & M costs make a costing risky. Not only are the costs highly site-dependent, but they are dependent on a solid market development.

However, cost data are quoted in the literature. Whether these data are accurate has to be doubted. The data are only used here to give some tentative hints. Better data on costs of WECS will certainly become available as utilities and manufacturer gain installation and operating experience.

Costs of 1980 $ 1218/kW for the MOD-2 are cited in an American report [14], based upon a production level of 120 units. The costs include site related cost (assess road, land, transmission) and annual O & M cost.

A cost breakdown of the NIBE wind turbine concept is given in [11]. On a 1978 price level $ 2400/kW result (value added tax included). As for a production in quantity and a modified design, reduction of about 50 % are supposed to be likely, [2]. As well as for the MOD-2, the costs include site preparation, roads, etc.

The net manufacturers cost for the first prototype of GROWIAN amount to about 9 Mill. dollar (1 US $ = 2.5 DM) corresponding to $ 3000/kW [7]. Cost estimates concerning the owners cost are not given. The manufacturer cost breakdown of GROWIAN is shown in Fig. 5.1, [7].

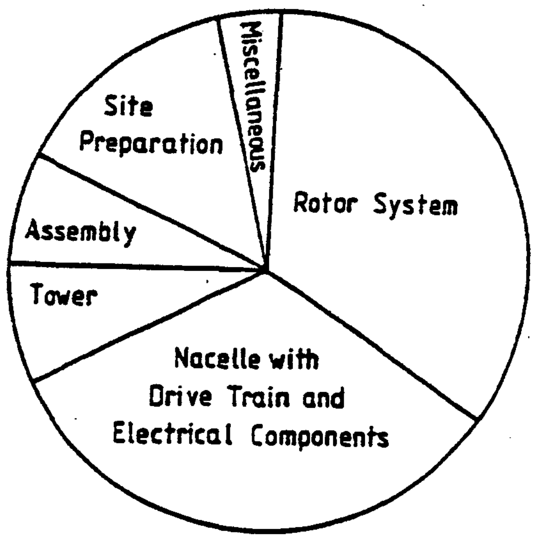

Fig.5.1: Manufacturers cost breakdown of GROWIAN

About 30 % of the costs relate to the rotor system as well as for the nacelle including drive train and electrical equipment. Especially these cost items are announced to be reduced in a mass production. For a production of 100 units, which allows for improved and rationalized manufacturing processes with special jigs and tools, a cost reduction of 45 % is assumed. That is the manufacturers cost would be about $ 1650/kW. The cost estimates of GROWIAN are given in 1981 dollars.

Finally, turnkey delivery cost per Aeolus wind turbine are given in a Swedish paper [3]. The manufacturers cost are estimated to be 1981 $ 2053 (1607) if a number of 10 (100) units is fabricated and implemented. The owners cost are estimated to be equal for 10 or 100 Aeolus turbines amounting to 1981 $ 491. (1 $ = 5.6 skr).

Assuming values of 8 % (MOD-2), 10 % (NIBE), 6 % (GROWIAN) and 8 % (Aeolus) for the annual escalation rate, the cost estimates are extrapolated up to 1985.

The projected costs per wind turbine are compared with the calculated breakeven values in Tab. 5.40 through Tab. 5.43. Note, owners cost are not or only partially included in the unit cost projections. The calculated breakeven value has to comprise all the costs incurred over the lifetime of the turbine. That is, manufacturers cost and owners cost are included. Cost items are, for example, fabrication, installation, checkout, intercaing, O & M, fees, insurance, land lease.

If the present value lifetime breakeven value per wind turbine is below the projected wind turbine cost, then on economic grounds the utility should further consider wind turbines in its generation plan.

G R O W I A N				
	Sweden	Japan (TEPCO)	the Netherlands	manufacturer cost estimate in 1985 $ based on a production figure of 100 units
operating lifetime: 20 yrs	$ 3229-4945/kW	$ 4012-6013/kW	$ 3391-3882/kW	$ 2100/kW
operating lifetime: 30 yrs	$ 4051-7144/kW	$ 5092-8496/kW	$ 4406-5408/kW	

Tab.5.40: Breakeven values and cost estimates per GROWIAN

A e o l u s		
	Sweden	manufacturer cost estimate in 1985 $ based on a production figure of 100 units
operating lifetime: 20 yrs	$ 2812-4763/kW	$ 2850/kW
operating lifetime: 30 yrs	$ 3512-6867/kW	

Tab.5.41: Breakeven values and cost estimates per Aeolus

M O D - 2			
	San Gorgonio SCE system	Ludington/ CPC/DE system	manufacturer cost estimates in 1985 $ based on a production figure of 120 units
operating lifetime: 20 yrs	$ 3030-3335/kW	$ 1713-1848/kW	$ 1800/kW
operating lifetime: 30 yrs	$ 3984-4462/kW	$ 2206-2468/kW	

Tab.5.42: Breakeven values and cost estimates per MOD-2

0 . 8 M W wind turbine			
	Japan (TEPCO)	the Netherlands	cost estimates for the NIBE design in 1985 $ based on a mass production
operating lifetime: 20 yrs	$ 2548-5085/kW	$ 2966-3382/kW	$ 2300/kW
operating lifetime: 30 yrs	$ 3230-7195/kW	$ 3838-4686/kW	

Tab.5.43: Breakeven values and cost estimates per 0.8 MW wind turbine

Based upon the comparison, it may be indicated that wind turbines are likely to be viable in the near future for utilities with good wind regimes and a high cost electricity generation.

This is indicated best by means of the two utility/site combinations assessed for the United States. The SCE system heavily depends on oil fired capacity. A displacement of oil and coal in the ratio of 9 : 1 by wind is therefore assumed for the value determination. The CPC/DE system is projected to depend mainly on coal and oil. Hence, coal and oil is assumed to be displaced in the ratio of 6 : 4. As a consequence, the MOD-2 is likely to become much easier competitive in the SCE system than in the CPC/DE system.

Even a number of 500 or 1000 wind turbines may still be competitive in the utility systems of the four participating countries, if one takes into account cost reductions through learning and production in quantity. However, wind turbines as capital intensive systems will suffer more from high rates of interest than do fuel-cost intensive systems.

The indications, however, are based on the assumption that the ambitious cost goals can be achieved by the wind turbine manufacturers. To date, a skepticism about manufacturer cost projections and production tooling seems to be advisable. Furthermore, cost data on operation and maintenance are not available and thus remain pure guesswork so far.

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6 ECONOMIC AND ENVIRONMENTAL IMPACTS AND INSTITUTIONAL FACTORS

6.1 LAND USE

Even the largest designed wind turbines, such as the US MOD-5B (7.2 MW) or the German GROWIAN II (5.0 MW), are still very small generation units by contemporary utility standards. The principal thermal and nuclear power plants have power ratings of about 1.000 MW.

Thus, a large number of turbines needs to be installed in order to gain any significant influence on utility economics. The question arises where to locate all the wind turbines.

Japan: Grave environmental impacts exist, which will limit the number of wind turbines actually being installed. Space is rare and thus limited grounds with a fair accessability are available. A conflict with regard to the land-use as claimed by the expansion of built-up areas, the industrial development and the traffic systems is predictable.

The Netherlands: For reasons of good wind regimes the coastline is to be preferred as candidate site. However, the Netherlands are as well a densely populated country. Furthermore, public and private efforts exist to preserve scenic vistas (Dutch shallows), to establish nature parks, and to save buffer zones between industrial and/or residental areas. Thus, a Dutch study [22] estimated the total area suitable for siting large-scale wind turbines. A necessary condition of being a suitable area is an annual mean wind speed of 6.5 m/s in a height of 40 m. A total area of 10.435 km^2 resulted, corresponding to 30 % of the Dutch surface. According to the report, a total number of 34.575 1.0 MW wind turbines with a rotor diameter of 50 m and a hub height of 50 m could be erected. In our report a max. number of 3.600 0.8 MW wind turbines and of 900 3.0 MW wind turbines, which are characterized in Chapter 2, are valuated.

Sweden: As shown by the evaluation of the Swedish wind date, the coastal region of southern Sweden reaching from Stockholm to Göteborg and the island Gotland are potential siting areas. The preference is also stated in [24], and confirmed by the Swedish decision to install one of the prototype wind turbines on the island of Gotland and the other one next to Malmö. With regard to land-use little impacts exist.

USA: The number of turbines to be installed in the San Gorgonio area has been assessed by numerous studies, e.g. [4], [5]. San Gorgonio as well as Ludington are primary candidate sites with sufficient siting area. Possible impacts may arise by the ownership and the cost of land.

6.1.1 Off-Shore Siting

Public and private efforts to preserve the scenic coast (the Netherlands; Sweden) and its island labyrinth (Sweden) exist. Growing interest in establishing nature reserves and recreation areas is looming (the Netherlands). Residential areas, industry and traffic claim land (Japan). Conflicts with other interests and possibilities of land-use are predictable when determining sites of hundreds of wind turbines. Thus, it is enticing to build up the wind turbines off-shore.

However, there will be impacts with off-shore as well. To avoid visual pollution the clusters have to be erected far away from the coastline. Transmission losses and/or high costs for submarine cable linking the units to land arise. There will be obstructions to international and national navigation and fishing. Servicing possibilities are cut back. The accessibility is not guaranteed and in any case expensive. Depending on the sea bed material and the water depth, high construction costs may arise. Ice and wave forces will place exacting requirements on structural material and design and/or shorten the economic lifetime. On the other side the wind conditions might be much more promising than on land. For an extended discussion see [10], [13].

6.2 Interfacing and Transmission

From the point of grid stabilization it might be promising preferring a diversified siting (smoothing effect). Dispersed siting requires, however, construction and maintenance crews to travel longer distances between points. The total length of access roads and lines would also be longer, increasing the land impact. Thus, wind turbines clustered together in parks seems to be a promising option.

It is suggested to transmit the power from the individual units, which are grouped together, at the generator output voltage to a group transformer which steps it up to a higher voltage, e.g. 130 kV. The power should then be transmitted by overhead power lines to a single utility grid interface point. Detailed cost estimates for such an interfacing are given, for example, in reference [5].

In transmission planning, capacity requirements and overall system stability are dominant considerations. The transmission capacity requirements are determined by the relative geographical location of the generation, the load, and the total power transport requirements. In Sweden, for example, there exist distinct corridors of trunk-lines from south to north (tradeoff in generation and consumption). Two studies [9], [18] have considered transmission capacity needs and have shown those needs fall within normal requirements of transmission design. Since, the transmission system is vital to overall system stability and is critical when generators oscillate against one another, the above two studies have considered these needs and have found no unique transmission requirements to accommodate a wind turbine array. In addition, operating experience gained at sites will improve the understanding, [19].

6.3 Visual Pollution, Television Interference and Wind Turbine Noise

Whereas the restrictions caused by the cost of land, the accessibility and the insufficient wind regimes can be quantified within a certain margin, only qualitative statements about the visual pollution of a large number of turbines can be given so far. However, for a cluster of a large number of wind turbines the aesthetics might gain importance. The influence of the visual effect on the public perception and hence the acceptance of wind turbines depends basically on the rotor disk area, the height, the material, the colour and the velocity of moment.

In Fig. 6.1 and Fig. 6.2 different wind turbines are scaled up, [8], [11].

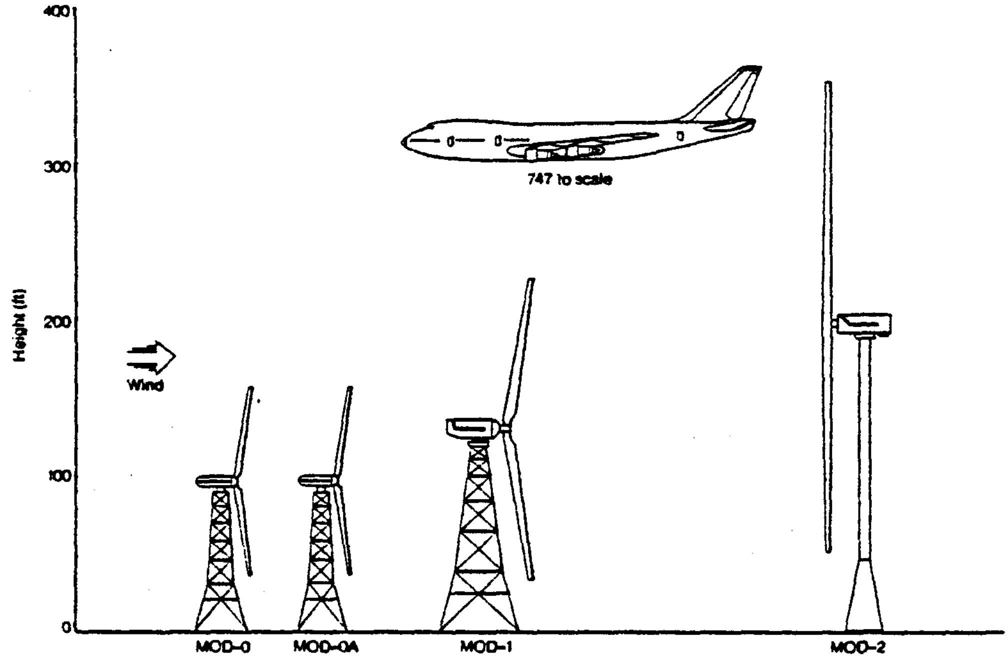

Fig.6.1: Federal large wind turbine program: scaling up horizontal-axis machines

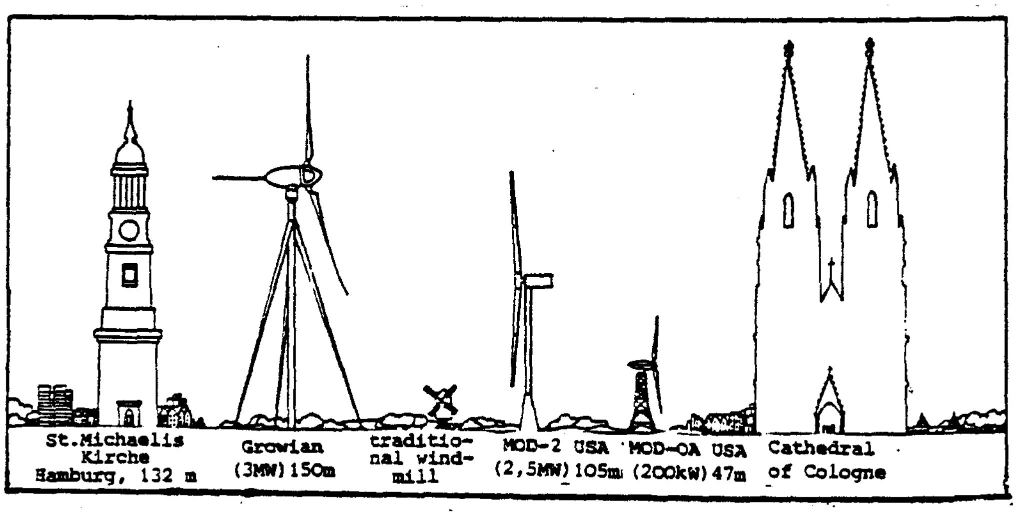

Fig.6.2: Size of wind turbines compared to German sights

Of course, there exist buildings, such as towers and skycrapers, of equal or greater height than wind turbines, but these buildings usually are located in densely built-up areas, like downtowns. The potential wind turbine sites, however, are located away from concentrations of population.

The visual pollution of wind turbines having hub heights of 50 m and 100 m was recently investigated in a Swedish report [7]. The following items turned out to be of importance for the perception of wind turbines:

- The rotation of the blades may become intrusive.
- The visual pollution of a small number of wind turbines having hub heights of 100 m is likely to be less than the visual pollution of a large number of wind turbines having hub heights of 50 m.
- In a flat, open landscape the theoretical length of visibility is about 40 km for a 100 m unit. In practice the length is limited by the visibility conditions due to the weather and due to the screens in the landscape, i.e. topography, vegetation and buildings.

Studies have shown that the rotating blades of a large wind turbine can interfere with TV reception. In the worst case the interference can still produce objectionable video distortion at distances up to a few kilometers, [20]. Noise, according to the understanding of the community in the neighborhood, is reported at Boone, N.C., where the MOD-1, a 2.0 MW downwind machine is located. One of the reasons is identified as the interactions between low frequency blade and tower. To which extent noise may be of annoyance with other turbines cannot be answered so far. For a detailed discussion of both the interference and the noise the reader is referred to [23].

6.4 INSTITUTIONAL FACTORS

Closely related to the siting of wind turbines and the power transmission problem are a number of legal issues. The following issues shall be stressed:

Building codes and safety codes are necessary in order to guidline the construction and erection of the turbines. These codes certainly would facilitate the local approval and would promote a production in series.

Cluster of wind turbines have to be reconciled with the physical planning in affected areas. Especially the zoning between urban and suburban areas has to be taken into account.

The issue of acquiring "wind rights", or guaranteed access to the wind resource will be vital to the development of wind energy, [16]. Consideration must be given to the question of how land-use policies and regulations will affect the siting of wind turbines. Otherwise possible changes in the land-use give rise to long-term litigation. At short-term the incentives of investment are impaired, when wind rights are formulated.

Whenever cluster of wind turbines are owned by non-utilities, codes will be required to guarantee that appropriate prices for the electricity are paid by the utilities. This, of course, poses the question about the buy-sell rate structure and the demand charge. The guarantee of a sale at a price equal to a utility's avoided cost (a best case), will allow the investors to calculate the cash flow of their expenses with a greater certainty. The

Public Utility Regulatory Policies Act (PURPA) of the USA, enacted in 1978, determines for a new class of utilities (small power producers) that the established utilities must buy power from the producers at the utilities' avoided cost, i.e., the dollar amount the utility saves due to the use of power of small producers. Avoided cost payback rates according to PURPA are already enacted by many states of the United States. However, still uncertainties due to potential changes of US government policy and court action do remain. The current regulatory and financial market conditions of the United States are discussed in great detail in [3], [14], [15]. The issue of buy-sell rates is not yet discussed in the other countries.

All the legal issues encountered surely pose a barrier to wind turbine siting. However, they should not pose a significant problem, as long as early steps are carried out in order to smooth the legal and institutional uncertainties, which are tied to the innovation of this new energy technology.

6.5 MOTIVATING MARKET DEMAND

Experience shows, and good business management dictates, that major financial investments in equipment and facilities will only be made where the ratio of "knows" to "unknows" is greatest. In the view of utilities the degree of unknows is a major barrier to implementation of wind turbines. A successful demonstration program that gives the utilities the knowledge and information they require to make sound business decisions would be a valuable step. The federal DOE and the Swedish wind energy program have demonstration programs as an integral part of their plan.

However, the step from the governmental funded stage to ultimate commercialization is not yet done. The reason for that fact can be denoted as commercialization dilemma, according to [14]. This refers to the situation where, in the near term, the wind turbine costs are too high, operating characteristics too uncertain and conventional energy costs too low to make the wind option cost effective. The wind turbine costs, of course, could be reduced by mass production. However, sceptical investors are not willing to give orders allowing mass production, [15].

The situation and the effects shall be discussed for the United States, as the most extensive efforts to implement wind power are taken in this country. In the last few years a wide variety of federal and state legislation has been passed to encourage renewable energy technologies in general and wind power in particular. The key laws are

- The Public Utility Regulatory Policy Act of 1978
- The Crude Oil Windfall Profits Tax Act of 1980
- The Economic Recovery Tax Act of 1981
- The Wind Energy Systems Act of 1980.

For an extensive discussion of these laws see [14].

With the current mix of incentives, such as tax credits, grants, low interest loans, supporting wind power, one might think that the commercialization dilemma would be resolved. However, the incentives that exist do not contain many benefits for potential investor-owned utility or industrial owners of wind turbines. The process associated with utility regulation constitutes a barrier to wind power in two aspects, [14]:

- Utility fuel costs are generally reimbursed almost automatically through fuel adjustment clauses while capital costs are recovered in a politically contested and high risk rate of return proceeding.
- Total utility returns are fixed and not a function of risk. If a utility invests in wind turbines and they prove successful, benefits flow through to the consumers. If problems develop, local PUC's are likely to extract some measure of penalty from utility stockholders. Thus the utility contemplating a wind turbine investment sees only "downside" risk and no "upside" benefit for its stockholders.

Most observers agree the key to wind power's impact on the nation's energy situation lies in large wind turbines and that utility customers for such machines will constitute the largest share of the market. Thus, a key question for wind turbine commercialization is whether there will be enough activity and experience in the near term with large wind turbines. If the market does not develop rapidly or (and worse) if early demonstrations provide technically unsuccessful, the rate of ultimate wind power utilization will slow considerably as utilities proceed cautiously with single turbine experiments, lasting several years, followed by small wind parks and only then (10 to 15 years from now) followed by substantial wind power use. Based on current assessments of the commercialization potential of all the utilities who provided data for the case studies, only the Southern California Edison Co. established a goal of 560 MW nameplate of installed wind turbine capacity in the midterm (by 1990), [21].

So far, however, manufacturers are uncertain and highly sceptical about the market. Facing significant investments in product development and production tooling, these companies are concerned that the market for large-scale wind turbines will be insufficient should the various federal, state, and local incentives be repealed or allowed to expire. These worries are exacerbated by uncertainties in future interest rates, fuel costs, and the ability to reduce wind turbine costs through mass production.

Even if the federal support were maintained, its success will depend upon the manner and extent to which the various parties (manufacturers, entrepreneurs, investors, financiers, utilities, PUC's and government) are willing to take risks and share returns in the next years.

6.6 Positive Economic Impacts

Of course, economic, operational and environmental impacts of large numbers of large wind turbines may pose barriers to commercialize large wind turbines.

However, due to the knowledge that the conventional energy sources are diminishing and their tolerance both for the environment and for the economy can no longer be accepted unchecked, there is the necessity to judge wind power not only on a business (utility) level. To schedule the future energy posture a socio-economic point of view has to be taken. To this respect the availability of the fossil resources, the public opinion concerning the acceptability of nuclear energy, the reduction of pollution, the evolution of industry and employment - to name only a few of the factors involved - should be taken into account.

Of course, an evaluation on a socioeconomic level has to proceed according to the principle of keeping costs of electricity to a minimum and maintaining at the same time a generation with an indexed reliability. However, the notion of costs needs to be more broadly defined. Three key factors, namely the pollution, the dependence and the scarcity have to be taken into account. The social costs related to these factors are presently not reflected in market prices of electric energy and do not appear in the cost budget of an economic analysis on a utility level.

6.6.1 DEPENDENCE

The dependence of electricity generation on finite and diminishing resources is pronounced in all of the four countries. The situation of Japan is used to illustrate this issue:

Tab. 6.1 shows for Japan the dependence of electricity generation on finite resources in 1979 [2].

fuel	percentage
nuclear	11.9
coal	6.2
gas	10.8
hydro/geothermal	14.5
oil	56.6

Tab.6.1: Electric power supply in Japan in 1979

Of course, Japan like the other countries is struggling to cut down its dependence on oil. The main reasons are the shrinking world reserves, the looming uncertainty in availability and above all the expenses for this resource.

However, Japan is not only dependent on oil imports. The dependence also holds for imported coal, uranium and gas. The drastic dependence on imports is summarized in Tab. 6.2, which gives both the pattern of energy supply in 1978 and the dependence on imports [1]:

oil	71.9	dependence on imported energy	86.0
solid fuels	14.4		
gas	4.5	dependence on imported oil	99.8
nuclear	4.1		
hydro/geothermal	5.1		

Tab.6.2: Japanese energy supply in 1978 and rate of dependence

Projections for the future electricity supply declare that the dependence on oil can be reduced, but to the debit of a dependence on imported coal and uranium.
A projection of the electric power supply in 1995 is given in Tab. 6.3, [1].

fuel	percentage
nuclear	39.4
coal	14.9
gas	19.5
hydro/geothermal	15.7
oil	10.5

Tab.6.3: Projection of electric power supply in Japan in 1995

Thus, already confronted by a deficitary balance of payments caused essentially by the costs of oil, the projected coal and uranium imports are not likely to bring relief. It may be concluded that within the present energy policy of Japan the dependence on imports of finite resources will remain. However, an independence of the national energy supply is a prime reason for looking for alternative sources while planning the future energy policy. It is thus entirely imaginable that from a socioeconomic point of view the electricity generation based upon domestic resources will be valued higher than a production which is highly dependent on imports. On a business level this economic goal of energy independence would become visible when the government grants a subsidy on those electricity generating units whose fuels are independent on foreign controlled factors. Wind turbines use a free and domestic resource. Thus, this merit should be credited to this technology. Correspondingly, a generation of electricity based on imported oil, gas, uranium or coal could be penalized by additional taxation.

6.6.2 POLLUTION

This concern is illustrated by the example of California. Air pollution, for example, costs the residents of California millions of dollars each year through its effects on human health, agricultural crop damage, and the deterioration of natural resources. A host of air quality standards (Prevention of Significant Deterioration (PSD), Air Conservation Program (ACP)) are formulated, the siting of power plants must comply with. Since any new fossil fired power plant would generate emissions, the problem is how to accomplish a project whether without violating PSD and ACP regulations, or in such a way as to cause an improvement in the ambient air quality. Wind power may be an important factor in substantially reducing the emissions of electricity generation. To which extent the principal emissions (NO_x, SO_x, TSP, HC) may be reduced is extensively discussed in [4].

The partial substitution of oil by coal, as announced by some of the Participants in the Task, will not lower the deterioration of the environmental quality. High social costs are incurred to remedy the damages. Local discontent exists and is channeled to the thermal power plants being claimed to pollute the environment.

In the case of a social evaluation, costs of pollution have to be seen as costs of the electricity production. Obviously, not only the costs resulting from the reversal of the damage to the environment but also the costs being incurred by the prevention of the damage have to be considered. To influence the utility investment decision a conversion of these social costs into private expenses by taxation seems to be possible. Correspondingly, non-polluting resources such as wind energy can be credited by tax credits, subsidies or risk underwriting.

6.6.3 Scarcity

Only Sweden projects an electric power supply, which substitutes scarce fossil fuels to a greater extent by solar energies, whereas the other countries will still depend on diminishing resources. Tab. 6.4 gives a Swedish projection for 1990, [17].

fuel	percentage
hydro	45.5
nuclear	40.0
oil	13.0
renewables	1.5

Tab.6.4: Projection of electric power supply in Sweden in 1990

Projected for 1995 the national electricity supply of Japan shall depend on the fossil fuels coal, gas and oil by 44,9 %.

The two American utilities, which have been assessed for the integration study, are also faced by a scarcity of fuels. The Southern California Edison system is heavily dependent on oil fired capacity, with 75 % of the capacity being oil in 1980. Future addition of coal and nuclear capacity are projected to decrease oil capacity to about 56 % in 1995. The Consumers Power Company's capacity mix is composed of coal (50 %), oil (31 %), nuclear (11 %), and hydro (8 %) in 1982. According to [12], the ratio is expected to remain almost constant over the next 15 years.

The scarcity of the fuels used so far, will be even intensified due to the increased demand primarily of the Third World Countries. An estimate of the life-spans of the shrinking exploitable reserves of the major energy resources reveals the looming shortage. Considering different growth rates in the world-wide consumption, Tab. 6.5 is given [6]:

resource	life-span in years[a]		life-span in years[b]	
crude oil	28.4[c]	95.8[d]	19.3[c]	40.2[d]
natural gas	50.6[c]	181.7[d]	28.2[c]	53.8[d]
solid fuels	217.o[c]	3.516.6[d]	58.0[c]	126.3[d]

Tab.6.5: life span of major energy resources.
a) basis: world-wide consumption of 1979, annual growth rate = 0 %.
b) basis: world-wide consumption of 1979, annual growth rate = 4 %.
c) based on proven exploitable reserves.
d) based on estimates of the exploitable potential.

An impending scarcity of the conventional fuels and the necessary adaption process is currently not anticipated by the market and the fuel prices. However, a scarcity of gas, oil, coal and uranium will give rise to costs within the entire economy. Wind power is created by a resource which is abundant. This advantage has to be credited to wind turbines. It would be possible, by means of corresponding taxation, to take into account the looming tendency to scarcity already in the present cost calculations of the electric utilities.

6.6.4 Nuclear Energy

As current energy sources are being rapidly consumed and demand for them continues to grow, they are becoming increasingly scarce, and there is the tendency to turn toward nuclear energy. Despite the fact that there are unexpected breakdowns in operation and substantial increases in construction costs looming mainly due to safety requirements, this energy source is still proclaimed to provide low cost electricity to customers, both reliably and efficiently at best. However, this energy source involves as yet numerous unsolved problems and both private and social costs that are immeasurable so far. Even if there were sufficient reserves of uranium and of other nondispensible elements such as chromium and molybdenum, even if there were reliable solutions with regard to safety requirements, reprocessing, and ultimate waste disposal, the costs that then have to be expected will be enormous and must be borne unalterably by future generations. As for minimizing social costs, attention must, in this case, be paid to evaluating competitive generation processes under the same starting conditions. When, for example, the construction of nuclear power plants is supported by governmental guarantees in order to underwrite the risk that is at most partly borne by the utility industry, and/or substantial advance governmental payments are borne on the R&D field of nuclear energy, wind turbines have to be credited by a corresponding amount if compared with the former on a socioeconomic level.

6.6.5 Socioeconomic Option

Economic and social policy should be aimed at a cost-effective energy supply, which as much as possible is resistant against foreign-controlled factors. A far-reaching dependence on energy imports can strongly affect the GNP, as demonstrated by the oil crises of 1973 and 1979. The national energy policy should also ensure that the social and ecological costs are minimized. To achieve this cost goal all energy resources should be considered, both by looking at ways of making better use of the diminishing nonrenewable resources and by conducting comprehensive research and development work in the field of the renewable resources.

Wind turbines, no matter how big or how many, cause no radioactive waste, no air pollution, no depletion of scarce resources. Instead, wind energy is a safe, domestic, non-polluting and abundant energy source. Of course, the siting of wind turbines will be affected by impacts, such as land use, wind rights, safety codes. However, none of the problems is insurmountable, as long as early steps are carried out. The utilization of wind energy could lead to a reduction in the demand for diminishing and finite fuel and energy supplies. However, grid-connected large-scale wind turbines owned or controlled of electric utilities have to be operated in order to gain knowledge and experience. High hopes of 'windo-holics' and enthusiasm spread by paper studies are no substitute for performance. What is needed now are extensive proofs of a safe operation and of a satisfactory quantity and quality of electricity produced. Additionally, such a demonstration is a necessary means to refuse local or utility distrust of this new technology.

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